# SEAL QUALITY AND DISTRIBUTION IN THE SOUTHERN TARANAKI BASIN LATE CRETACEOUS TO EOCENE SECTION AND IMPLICATIONS FOR HYDROCARBON TRAPPING

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A thesis submitted in partial fulfilment of the requirements for

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# Abstract

Failure to discover hydrocarbons within Late Cretaceous and Paleocene strata in the southernmost Taranaki Basin is postulated to be in part due to the limited coverage of effective top seals above these reservoirs. Effective top seals are formed by fine grained, clay prone sediments, which are deposited mainly in marine environments. This study presents paleogeographic maps for the Latest Cretaceous North Cape Shale and Early Eocene E Shale, which are probable and proven top seals respectively for hydrocarbon reservoirs in the offshore Taranaki Basin of New Zealand.

The aim of this thesis is to define the spatial distribution of thickness and permeability for two primary seal units formed during two marine flooding events (transgressions) of Latest Haumurian and Waipawan ages. These seals have been characterised using a selection of 12 petroleum exploration wells along with seismic reflection data from 20 2D seismic surveys and five 3D surveys. Top and base seal horizons identified from wells were mapped in seismic data and interpreted over the study area, resulting in an improved understanding of seal-rock spatial distributions. Petrographic and mercury injection capillary test results were collated from samples within the two primary seal intervals to identify their common properties and further analyse what constitutes an effective seal in this part of the basin.

The North Cape Shale shows more widespread distribution than the E Shale and can be seismically traced further south, whereas the E Shale is thicker but is limited to a narrower distribution, changing facies type to a coastal plain/non-marine facies near the north western boundary of the study area. Risk of topseal absence increases at both intervals towards the southern boundary of the study area.

# Acknowledgments

Firstly, thanks to my wonderful wife Louise for putting up with my late nights studying, your proof reading prowess and never complaining that I was AWOL while finishing this work. To my two beautiful daughters, Delphi and Stella, for (mostly) sleeping at night so I could get this work done. To my supervisors Mac Beggs, Neville Smith, Andy Nicol and Kari Bassett for your support, guidance, comments and feedback. And lastly to Simon Lange, Gus O'Hagan and the staff at OMV NZ for the encouragement and financial support to enable me to write this thesis.

# 1. Introduction

## 1.1 Project Aims and Outline

A seal is a generic term describing the capping layer that prevents hydrocarbons from migrating out of traps. They are a crucial part of a "petroleum system" which encompasses the elements needed to form a commercial sized oil or gas accumulation (Downey, 1984; Watts, 1987; Magara, 1992; Sales, 1997). Petroleum systems consist of source rocks heated sufficiently to expel hydrocarbons, then migration into a porous container (reservoir), and a structure or "trap" which is sealed by an impermeable layer to prevent hydrocarbons escaping. Research efforts in Taranaki are often focused on identifying and understanding the source and reservoir elements of the petroleum system, with few studies explicitly targeting the seals. This thesis will concentrate on understanding the distribution and properties of seal rocks in an effort to predict where they are likely to be absent or at a higher risk of leaking hydrocarbons. This seal information is key for future exploration of hydrocarbons in New Zealand.

In the Taranaki Basin there is a southern limit to hydrocarbon prospectivity for Late Cretaceous and Paleocene reservoirs. This is inferred to occur because there appears to be no effective topseal to prevent leakage from hydrocarbon reservoirs (Thrasher, G., pers com. 2015). This potential leakage is problematic for further exploration as many of the remaining untested hydrocarbon traps reside within Late Cretaceous to Paleocene reservoirs. Determining the locations at which this boundary in the effective seal occurs is a key focus of this research. The thesis aims to map the spatial distribution of good quality seal within two units of the offshore southern Taranaki Basin of New Zealand; the Latest Cretaceous "North Cape Shale" and the Early Eocene "E Shale".

To accomplish the primary goal, the thesis draws on interpretation of publicly available 2D (11,000 line km) and 3D (1050 km$^2$) seismic reflection surveys and analysis of wireline and core data from 12 petroleum exploration wells within, and in close proximity to, the study area (Figure 1.1). These data have been used to select a study area for investigation (Figure 1.1) and to determine the areal variations in thickness and effective permeability of the seal intervals examined. In addition to the primary goal, the thesis also examines a number of secondary questions including, what constitutes a good seal rock? What are the physical properties of the two seal rocks? And what is there in common between the two seals?

To address the questions outlined, and to map the location of the southern boundary of effective seals for both units, the thesis is presented as follows:

Chapter 1: Outline of thesis, overview of geology, seals and previous petroleum exploration;

Chapter 2: Review of the southern Taranaki Basin's stratigraphy and the geological processes that have influenced the study area from the Cretaceous to the present;

Chapter 3: Examination of the properties and controls on seal rock quality;

Chapter 4: Detailed investigation of wells that penetrated the two seal packages, their characteristic wireline signatures and distribution over the study area and surrounding region;

Chapter 5: Interpretation of seismic data based on regional wells as control points and extrapolating south to the study area where the sealing packages appear to thin or pinch out;

Chapter 6: Construction of paleogeographic maps of the distribution of the seal rocks, combining from chapters 2-5 to develop a picture of where the southernmost mapped distribution of effective seals occurs;

Chapter 7: Summary and conclusions.

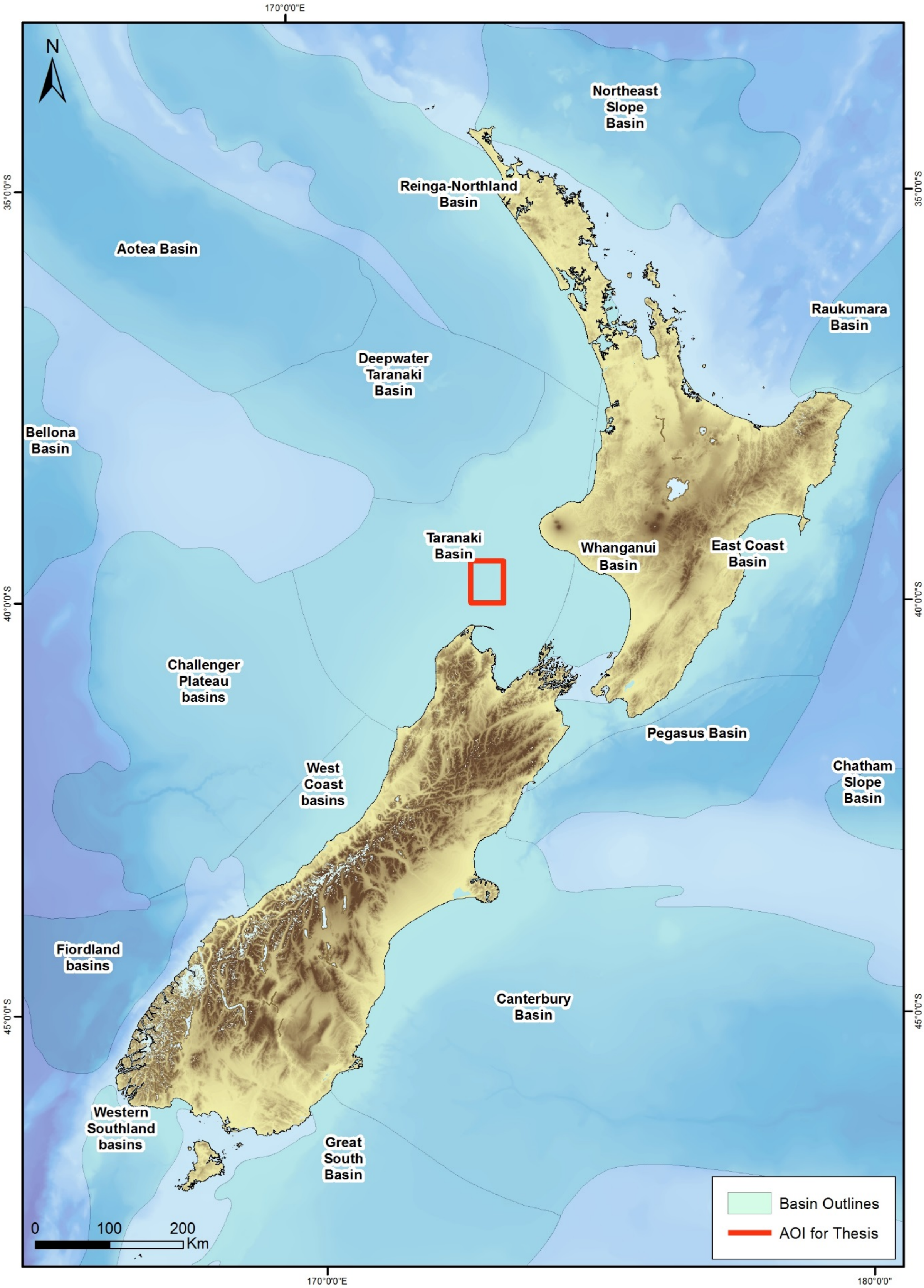



*Figure 1.1 Map of New Zealand with outlines of sedimentary basins shown as well as the study area (AOI) for this thesis within the southern Taranaki Basin. Basin boundaries sourced from the NZPAM 2015 data pack.*

## 1.2 Geological Overview

The mostly submerged landmass of New Zealand[1] has numerous sedimentary basins with active petroleum systems, however the only basin where commercial hydrocarbon extraction occurs at present is the Taranaki Basin (Figure 1.1). As such, it is currently the most valuable basin for the economy of New Zealand with proven and probable reserves of 8 trillion cubic feet of natural gas and 588 million barrels of liquids (oil/condensate), suppling domestic gas needs, methanol production and transport fuels (MBIE, 2016). In addition, export of petroleum liquids contributes significantly to New Zealand's economy.

The Taranaki Basin is situated mostly offshore on the western side of New Zealand between the North and South Islands. At the eastern margin, it is bounded by the Taranaki Fault and the Wanganui Basin (King and Thrasher, 1996; Kamp et al., 2004). To the north the basin runs contiguously into the Northland/Reinga Basin, (Isaac et al., 1994; Herzer et al., 1997) and to the west it continues into a region of deep-water known as the Deep Water Taranaki Basin (Uruski et al., 2002). At the southern extreme the basin is uplifted, exposing outcrops of the pre-Miocene section in the onshore areas of north-west Nelson (Nathan et al., 1986; King and Thrasher, 1996; Armstrong et al., 1998).

Sedimentary fill in the basin consists of mid-Cretaceous to Quaternary deposits up to eight kilometres thick (Holt and Stern, 1994; King and Thrasher, 1996). In the southern Taranaki Basin (STB), deposition was initiated in a rift setting contiguous with the breakup of Gondwana c.100 Ma (Bache, 2014; Strogen et al., 2017). By the latest Eocene, the STB was gradually flooded and subsiding, with sedimentation changing from terrigenous and nearshore to predominantly marine fine grained facies with increasing calcareous content as the basin was starved of clastic input. Compression, uplift and subaerial volcanism occurred during the Miocene as the entire basin moved from a passive margin to a compressional foreland setting, followed by intra-arc rifting in the north and central basin which continues today (Holt and Stern, 1994; King and Thrasher, 1996; Giba et al., 2010; Reilly et al., 2015).

[1] New Zealand is now formally recognised as part of the extensive (and mostly submerged) continent of Zealandia (Mortimer et al., 2017)

## 1.3 Seals

Seals can comprise any rock type, but are most commonly fine-grained clay or mudstones with low permeability, which is a result of having narrow spaces, or "pore throats", between each grain. Rocks with pore throat sizes of less than <0.1 micron (µm) can generally be regarded as seals, with further subsequent decreases in pore throat size enhancing seal quality permitting greater volumes of hydrocarbons to be trapped. The controls on permeability reduction vary and are attributable to compaction with increasing burial depth, grain size, mineral content and diagenetic alteration during burial (Downey, 1984; Sutton et al., 2004). Depositional environments that favour the preservation of fine-grained material such as the deep ocean floor or river deltas should be conducive to forming extensive packages of seal rocks. Conversely, high-energy environments such as beaches or coastal plains would conversely result in deposition of poor quality seal rocks.

Several exploration wells have been drilled searching for oil and gas accumulations in the southernmost STB (Figure 1.2). Commercial oil accumulations were discovered in the Maari-Manaia fields in shallow Miocene and Eocene reservoirs but none of the wells have encountered commercial discoveries in the pre-Eocene section despite encouraging shows of oil in some. Limited distribution of a widespread sealing cap rock for Paleocene to Cretaceous reservoirs in this area is hypothesized to have a major influence on the effectiveness of the petroleum system. At the Fresne-1, Cape Farewell-1 and Cook-1 well locations claystones capable of forming top seals over hydrocarbon traps have been noted as thin, rare or altogether absent. A similar sparse distribution of potential seals occur in onshore exposures of Paleocene and Cretaceous rocks in the Northwest Nelson area (Rattenbury et al., 1998). In the Hector-1 and Pukeko-1 well locations at key intervals, seal rocks are noted to be thick enough and of sufficient quality and lateral extent to form effective barriers for vertical hydrocarbon migration and allow the formation of reservoir-seal pairs capable of withholding oil or gas columns, at least of a limited height (PetroTech, 2015). The extent of these seals to the south beyond the confirmed well penetrations of Hector-1 and Pukeko-1 and north of Fresne-1 is poorly constrained. As such, the seal rocks in the southernmost Taranaki Paleocene to Cretaceous petroleum system deserves further scrutiny to establish if they are effective.

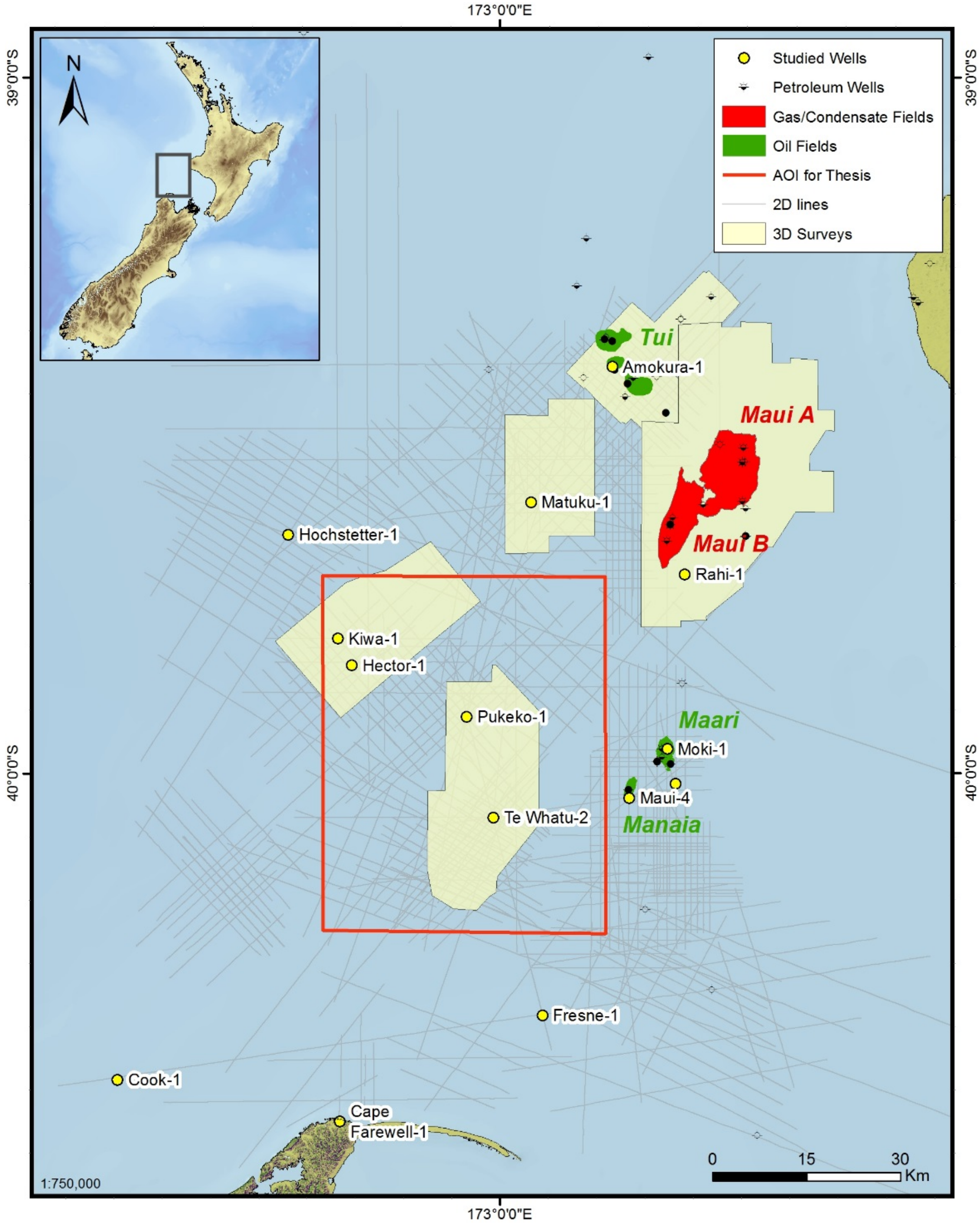



*Figure 1.2 Detailed map of the study area for this thesis. Wells that were examined in detail during the course of this work are named, with Cook-1 also included for reference. Additional well locations and discovered oil and gas fields are displayed for regional context.*

## 1.4 Previous and Current Exploration

The search for oil and gas reserves in the STB has been in progress for over 50 years resulting in moderate to good data coverage (Figure 1.2). Exploration efforts were carried out in two main phases - the 1970s-80s and early- to mid-2000s. Acquisition of the first reconnaissance 2D seismic reflection data occurred in the late 1960s during the same period that the giant Maui gas/condensate field was discovered 20 km to the northeast of the study area. This led to a focus on similar large four-way dip closures being targeted in follow up exploration wells in the basin.

Maui-4 (1970) was the first offshore exploration well in the area on the Manaia structure, and discovered a sub-commercial oil accumulation within the upper Kapuni Group (Shell, BP, Todd Oil Services, 1970). Following this early success, Fresne-1 (1976) was drilled by NZ Aquitaine Petroleum on a large inverted four-way dip closure similar in geometry and deformation history to the Maui-4 structure. It was unsuccessful and was plugged and abandoned without encountering significant shows of hydrocarbons (NZ Aquitaine Pet. Ltd, 1976).

After the NZ Aquitaine Petroleum licence was relinquished, the area was acquired by Shell, BP & Todd Oil Services who had identified a large, shallow-dipping four-way structure on 1974 vintage seismic data at the north-western extreme of the study area. Further 2D seismic was acquired and a well (Kiwa-1) was subsequently drilled in 1981. Good reservoir and seal pairs were encountered in the Eocene to Late Cretaceous but no hydrocarbons were noted. The acreage was subsequently dropped in 1982.

As a follow up to the early success of Maui-4, a satellite structure was identified and drilled by Tricentrol Exploration Ltd (the Moki-1 well) which discovered oil in the Miocene Moki Formation and Late Eocene Kapuni Group, which was also at the time deemed to not be commercial (Tricentrol Exploration Overseas Ltd, 1983). However, this discovery maintained interest in the southern Taranaki Basin and served to encourage further exploration efforts.

Petrocorp was the final explorer to investigate the study area in the primary phase of exploration and, following the acquisition of 2D seismic data in 1981 and 1982, identified a large, elongate, four-way structure in the centre of the study area. In 1986/87, after the engineering failure of Te Whatu-1 at a shallow level, the exploration well Te Whatu-2 was drilled to the base of the Eocene section but did not encounter any significant hydrocarbons.

A hiatus of exploration in the area followed for almost 20 years, despite constant exploration activity elsewhere in the basin. The discovery of the Tui field in 2003 in a Paleocene-aged reservoir 30 km to the north of the study area renewed interest in the STB. This interest was due to the realisation that numerous untested traps existed at deeper levels due to the presence of deep effective seals which had trapped a significant oil accumulation in the Tui area. NZOP drilled Pukeko-1 in 2004 in the centre of the study area and confirmed this deeper prospectivity. Good hydrocarbon shows were noted in Paleocene to Late Cretaceous reservoirs in Pukeko-1. Unfortunately, reservoir quality and oil saturation levels were low which led to the plugging and abandonment of the well (NZOP, 2004). The Pukeko-1 area was then relinquished.

In 2005, 3D seismic was acquired over the north-western part of the study region by AWE (Hector-3D) and an untested updip portion of the Kiwa structure was identified. This led to the drilling of Hector-1 in 2007 by AWE. This well was also dry and the area was surrendered.

Todd Energy continued exploration of the study region from 2004 to 2016 as part of the exploration permits 38494 (Tasman), 51313 (Te Whatu) and 54865 (Aihe). Substantial reprocessing of existing vintage seismic data was supplemented with new 2D seismic acquisition to create the first integrated seismic dataset for the STB. Additional regional 2D seismic lines were acquired in 2011 and a new 3D seismic survey, the Pipeline-3D, was carried out over the Te Whatu and Pukeko area. Several studies were completed including seismic mapping, mercury injection capillary pressure (MICP) tests of seals and basin modelling. Seal presence was identified as a principal risk and was a focus of technical studies to understand how it could affect the petroleum system (PetroTech Associates 2015; Viskovic and Reynolds, 2015). Results were encouraging enough for the authors to consider that if the E Shale was present, although variable in seal quality, it was capable of withholding a small to moderate gas or oil column. No detailed analysis was carried out on the North Cape Shale and its ability to retard upward flow of petroleum is uncertain.

The most recent exploration in this sector of the STB, from 2013 to 2018, is being carried out by OMV NZ Ltd, currently within exploration permit 60091. OMV NZ drilled the Whio-1 exploration well in 2014, 10 km east of the study area targeting Miocene and Eocene reservoirs but did not encounter significant hydrocarbons. No other operators are currently active in the region.

# 2. Overview of the Taranaki Basin

## 2.1 Structural Overview

The Taranaki Basin has a complex history stemming from multiple overprinting tectonic phases that have influenced sedimentation patterns over its c.100 Ma history (King and Thrasher, 1996; Strogen et al., 2014, 2014b, 2017). Taranaki Basin was originally formed as a series of rifted grabens and half grabens prior the extension and breakup of Gondwana into the separate continents of Australia, Antarctica and Zealandia. It is currently positioned on the western edge of the Australasian plate c. 300km horizontally from the Pacific plate subduction trough east of New Zealand. Four separate regions in the Taranaki Basin have been defined based on current tectonic activity: the Western Stable Platform, the Southern Inversion Zone, the Eastern Mobile Belt and the Northern Taranaki Graben (Figure 2.1). As this study is primarily focused on the Southern Inversion Zone and the transition area between this and the Western Stable Platform, the latter two structural regions are mentioned only for regional context. Further detailed tectonic information on Taranaki Basin can be found in King and Thrasher (1996), King (2000), Giba et al., (2010) and Reilly et al., (2015).

The Western Stable Platform (WSP) forms the western margin of the basin, with the border a roughly north- east striking line between the Cook-1 and Witiora-1 wells. The chief characteristics of the WSP are that it is relatively un-deformed, shallow dipping stratigraphy overlying the original extensional rift basins and low levels of tectonism since the initial rifting phase (King and Thrasher, 1996). By contrast, the Southern Inversion Zone (SIV) comprises a large area of uplift active from the Maui area north of Te Whatu-2 well to the South Island (Figure 2.1), resulting in regional uplift and tilting which increases to the south. Here, extensional normal faults from the Cretaceous to Paleocene rifting phase have been reactivated as reverse faults, forming steep north plunging anticlines, most of which have been drilled at least partially by petroleum exploration wells (e.g. Cook-1, Cape Farewell-1, Fresne-1, Surville-1, Tasman-1, Te Whatu-2) (King and Thrasher, 1996). Onshore exposures in the Golden Bay area include Cretaceous and Paleocene aged rocks - the only location these strata are visible at surface in the basin; Miocene and younger strata are largely missing due to erosion on the inverted blocks. Offshore near the Fresne-1 well, Miocene to Recent cover resumes and rapidly thickens northwards to over 2 km in the study area (Figure 2.2).

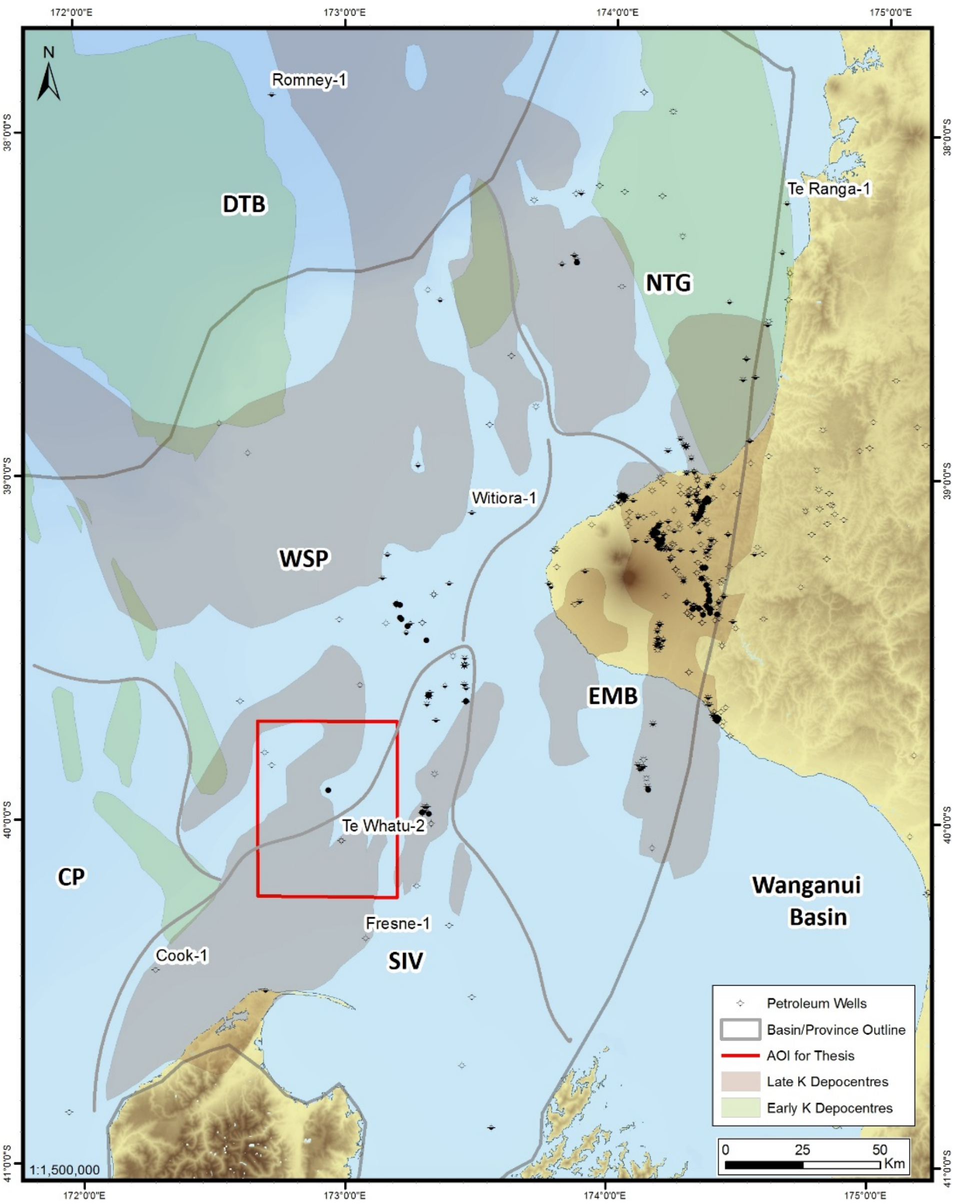



*Figure 2.1 Shaded areas indicate Cretaceous depocentres resultant from the primary and secondary rifting phases c. 103 and 77 Ma respectively overlain by the present tectonic provinces (NTG, North Taranaki Graben; DTB, Deepwater Taranaki Basin; EMB, Eastern Mobile Belt; WSP, Western Stable Platform; SIV, Southern Inversion Zone; CP, Challenger Plateau). Tectonic province outlines in grey are based on the author's working knowledge of the basin. The Cretaceous depo-centre underlying the study area and SIV is known as the Kahurangi Trough.*

## 2.2 Cretaceous Early Basin Development 103-82 Ma

The oldest sedimentary fill in the Taranaki Basin consists of the mid-Cretaceous Taniwha Formation (Figure 2.3). Confirmed spatial distribution of the Taniwha is limited to the north-eastern corner of the basin in the vicinity of the Te Ranga-1 well where it comprises of clastic-rich coal measure sequences deposited in a coastal plain setting, thickening eastwards towards the basin bounding

Taranaki Fault (Figure 2.4) (King and Thrasher 1996). Interpretation of seismic datasets by Strogen et al. (2017) suggested that further mid Cretaceous syn-rift deposits are also present near the distal Romney-1 well, at the base of the Moa Graben and in isolated pockets on the Challenger Plateau (Figure 2.1). Accommodation space was created by a small number (~20) of north-west and west-north-west trending normal faults active at this time which formed half grabens. These early half grabens were associated with the opening of the New Caledonia Basin to the north of Taranaki during the primary extensional phase in the basin c. 103 Ma (Strogen et al., 2017).

## 2.3 Late Cretaceous - Paleocene; Syn Rift 82–56 Ma

Late Cretaceous sediments are preserved as the Pakawau Group syn-rift deposits within faulted north-to north west trending en echelon sub-basins. This area of extension was referred to by Thrasher (1992) as the Taranaki Rift, a broad zone of crustal thinning linked to the opening of the Tasman Sea to the west during the basin’s second rifting event. Earlier normal faults were reactivated, with new rifts developing and migrating in a progressively southern direction throughout the Late Cretaceous to possibly earliest Paleocene c. 57 Ma (Strogen et al., 2017). In South Taranaki, the sub-basins formed by this secondary rift phase include the Kiwa, Pakawau and the Kahurangi Trough. Fluvial and terrestrial syn-rift fill was topped by transgressive sequences of shallow marine deposits.

## 2.4 Paleocene – Early Oligocene; Passive Margin 56-34 Ma

At the conclusion of the second extension phase the basin entered a period of tectonic quiescence (Reilly et al., 2015). Subsidence became regional over the wider area due to cooling of the thinned underlying continental crust. Short lived transgressive marine influxes occurred periodically, however the majority of the sedimentary fill was a series of regressional events building out as a prograding shoreline towards the north and west (e.g. Figure 2.4, 54Ma). This sequence is the Kapuni Group, which describes terrestrial and shallow marine successions deposited over this period in a large open embayment striking to the present-day north-west. Open marine environments persisted in the farthest west and north-west areas (Deep Water Taranaki/Northern Graben) (King and Thrasher 1996). In the south, the Taranaki Basin was bordered by the partly emergent Challenger Plateau with sediment sourced from the south east and east and also from emergent basement highs (King and Thrasher, 1996).

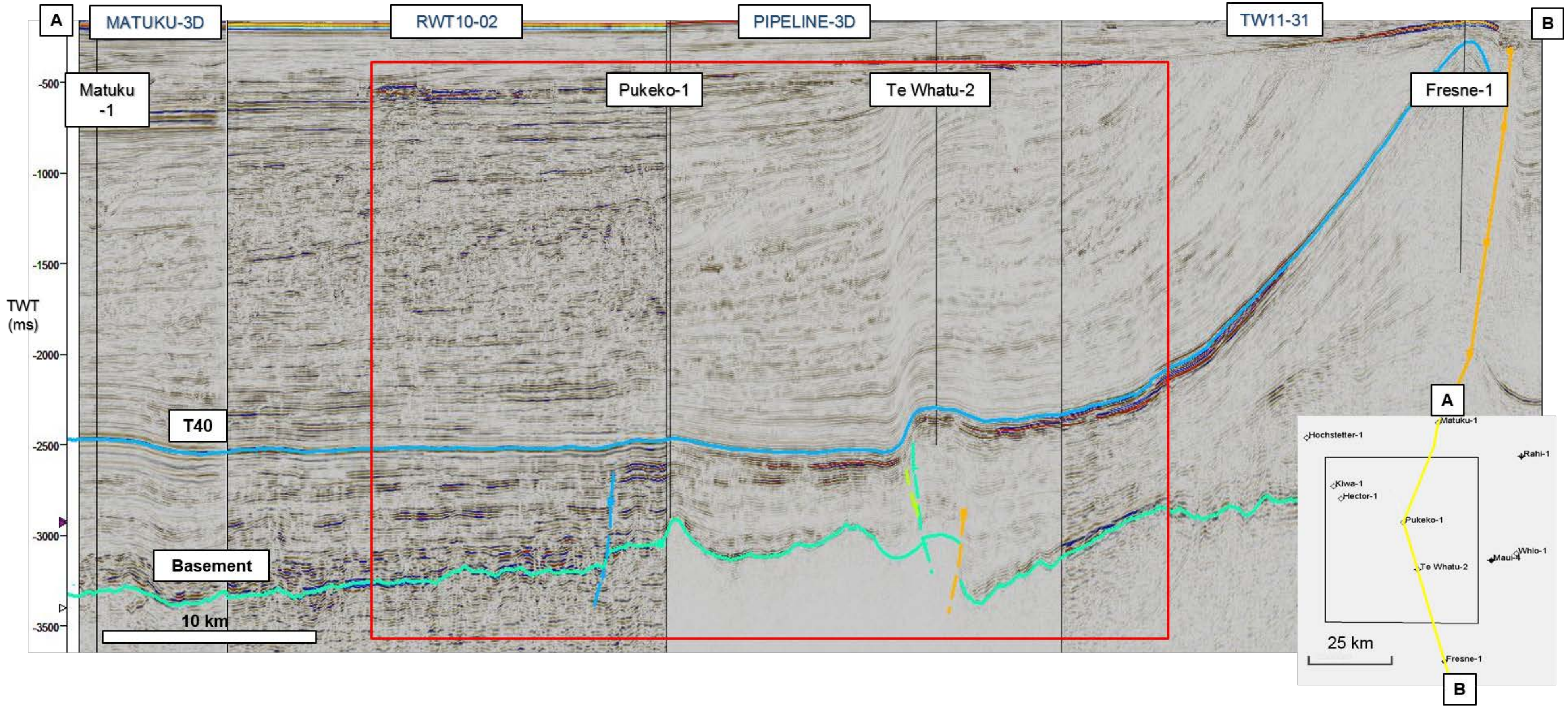



*Figure 2.2 Seismic transect through the study area (red box) showing well penetrations, an interpreted basement reflector (green), and a base Oligocene seismic marker (blue). Note the thinning and tilting of the post Oligocene section to the south. Centre of image shows the boundary between the WSP and the SIV where faults have been reactivated with steep reverse throw to accommodate shortening in the STB.*

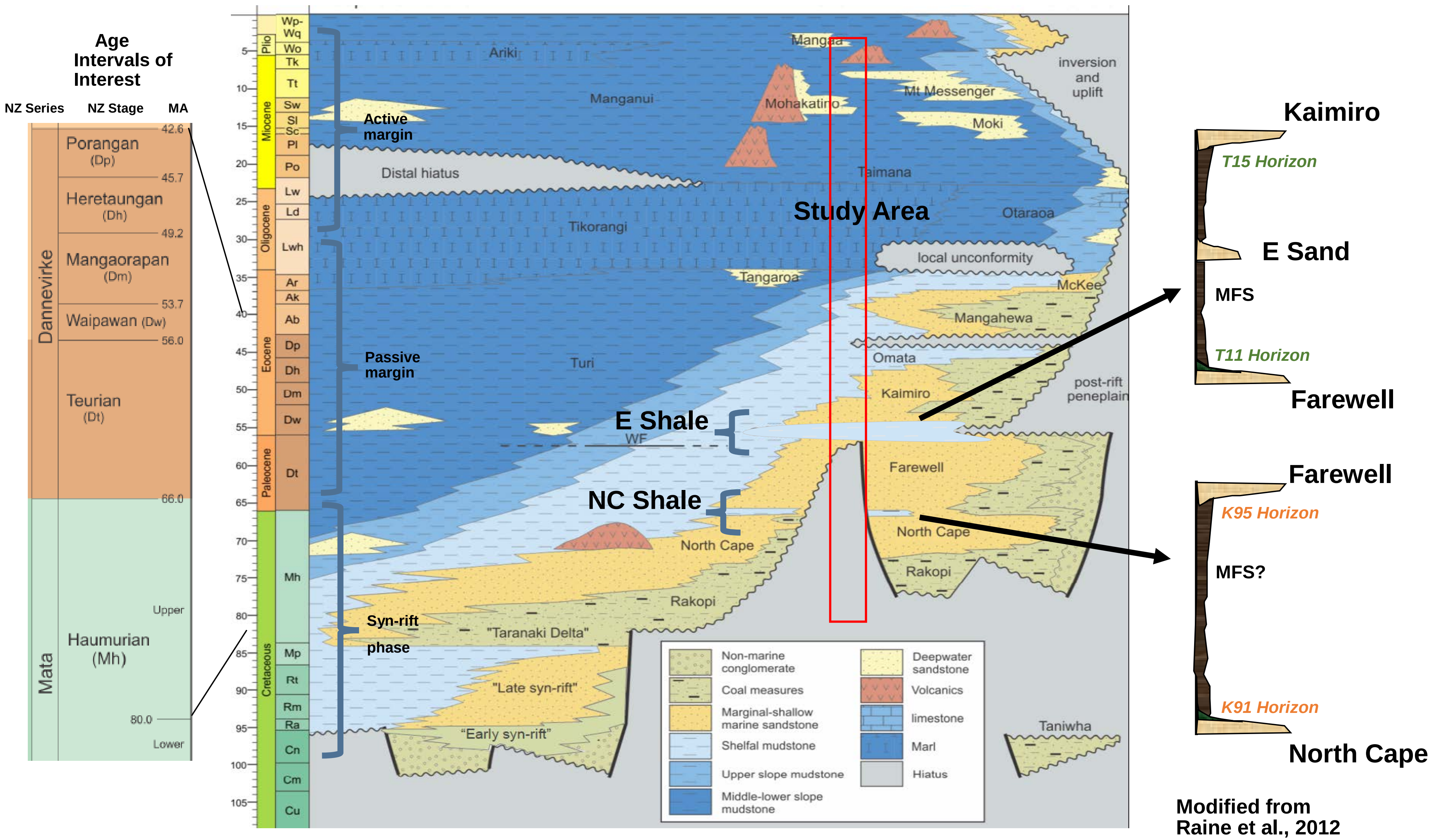



*Figure 2.3 Stratigraphic chart of the Taranaki Basin. Positions of the E Shale and North Cape Shale are shown in relation to surrounding formations. Relative position of the study area within the basin is shown inside the red polygon.*

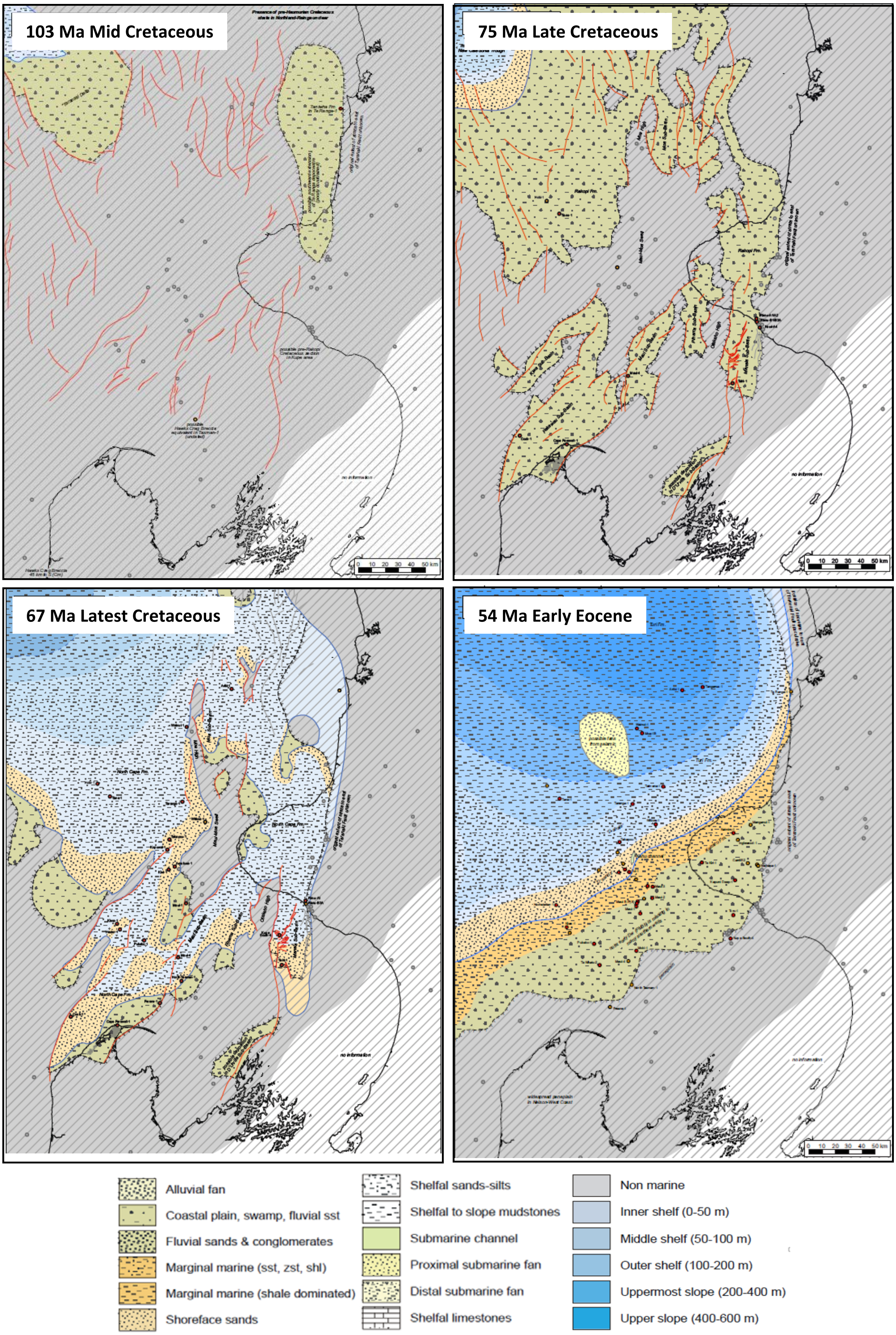



*Figure 2.4 Paleogeographic maps modified from Strogen (2011). Initial basin formation in mid Cretaceous rift phase (Taniwha Formation) through to secondary rift phase in Late Cretaceous (Rakopi Formation), Latest Cretaceous (North Cape Formation) and Eocene (Kaimiro Formation).*

## 2.5 Oligocene – Early Miocene; Transitional Phase 34-19 Ma

The Oligocene marked the point where all parts of the Taranaki Basin were below sea level as basin subsidence continued. A distinct reduction of clastic sedimentation defines the Ngatoro Group deposited during this period; thick sections of limestone are present at the eastern and south-western basin boundaries with more distal western areas preserving thin marls and calcareous clays as condensed sections at the basin slope and floor level (King and Thrasher, 1996). The effects of subduction of the Pacific plate below the Australasian plate, initiated to the north of the North Island in the Eocene, migrated south and then began to affect the Taranaki Basin from the Early - Late Oligocene or possibly the Late Eocene (King, 2000; Stagpoole and Nicol, 2008; Reilly et al., 2015). Convergence and uplift started at the eastern margin of the basin on previously normal faults, with these faults accommodating inversion and reverse movement which produced a foreland basin setting (Figure 2.5). These reverse displacements temporarily increased transgression over some areas by deepening parts of the eastern margin of the basin, the foredeep area, which then infilled with sediment supplied by the subsequent erosion of the eastern foreland bulge, the Patea – Herangi High.

## 2.6 Miocene - Present; Convergence 19-0 Ma

Reactivation of the Taranaki Fault as a thrust and the emergence of the Patea – Herangi High continued as the foreland basin developed further. Shortening in an east-west orientation continued throughout the Miocene, with reactivation of more distal westerly normal faults in the last 7 Ma (Reilly et al., 2015). A regressive sequence, the Wai-Iti Group, was deposited over this period, prograding into the basin in a wedge shape and gradually thinning with distance from the eastern and southern sediment sources. Clays, silts and fine sands entrained in turbidite flows were deposited in the wedge, starting at bathyal depths in the Early Miocene, becoming coarser and more clastic-rich as the foredeep area filled and built north-westwards as the shelf prograded (King and Thrasher 1996; Grain, 2008).

Submarine, basaltic-andesitic volcanic centres became active in the basin between the Early to Late Miocene in the Northern Graben as subduction of the Pacific plate continued, supplying material to melt the overlying Australian plate and initiate a volcanic arc which provided a further source of sediment in northern areas (Figure 2.6). Regressive sedimentation continued into the Pliocene and Pleistocene with the Rotokare Group - a predominantly fine grained clastic sequence of clays, silts and muds sourced from the newly emergent Southern Alps south of the basin. Deposition of the Rotokare Group continued the previous pattern of building the shoreline westwards in a series of clinoforms - the Giant Foresets Formation. Subsidence via sediment loading of the Western Stable Platform buried the central and north-western rifted zones to the deepest points in their burial history, while uplift and northward tilting at the Southern Inversion Zone exposed and eroded the sedimentary sequence from the Late Miocene to present (Reilly at al., 2015).

## 2.7 North Cape Formation

North Cape Formation was originally described by Suggate (1956) and refined by Thrasher (1992) as a Late Cretaceous, predominantly clastic section of strata comprising of interbedded sandstone, siltstone, claystone, conglomerate and coal measures. Its thickness reaches up to 1800 metres but is normally between 1-200 metres in localised sub basins. It differs from the underlying Rakopi formation in that it displays an increased level of marine influence, reduced (but not absent) development of coal measures as locally distributed members and appearing relatively bland on offshore seismic reflection data compared to the underlying Rakopi Formation which is brightly reflective (King and Thrasher, 1996). The North Cape Formation is widely distributed throughout the basin, present in the southern onshore area, as far north-west as the Romney-1 well, at the northern extreme of the basin (Ariki-1) and the eastern margin at Tahi-1 (SBPT Ltd, 1984; Palmer, 1984; King and Thrasher, 1996; Anadarko NZ Ltd, 2015). Deposition of the North Cape Formation occurred in shallow marine to terrestrial environments, including paralic settings and tidal flats; onlap also occurred onto basement highs that were emergent at this time (King and Thrasher, 1996).

## 2.8 Farewell Formation

The Paleocene-aged Farewell Formation consists of a series of interbedded sandstone, siltstone and claystone beds with rare local coal measures. In the petroleum well Kapuni Deep-1 (onshore Taranaki Peninsula), the Farewell Formation is up to 1670 metres thick (Shell, BP, Todd, 1984). For the most part, in the STB it is between 200-500 metres thick. The Farewell Formation was initially considered to be part of the Late Cretaceous Pakawau Group (Suggate, 1956), however, work by Raine (1984), King (1988) and Bal (1992) showed it to have a wholly Paleocene age and to be part of the Kapuni Group. The thickest sections of the Farewell Formation are within half grabens that were actively subsiding/under filled in the Paleocene with thinning onto nearby emergent basement highs. The formation also thins to the north and west of the Maui field where it becomes more marine and interfingers with the distal marine Moa Group. The Farewell Formation was deposited over the study area in terrestrial braided river systems draining from the Pakawau sub-basin to the south, emptying into a tidally influenced, shallow marine environment (King and Thrasher, 1996).

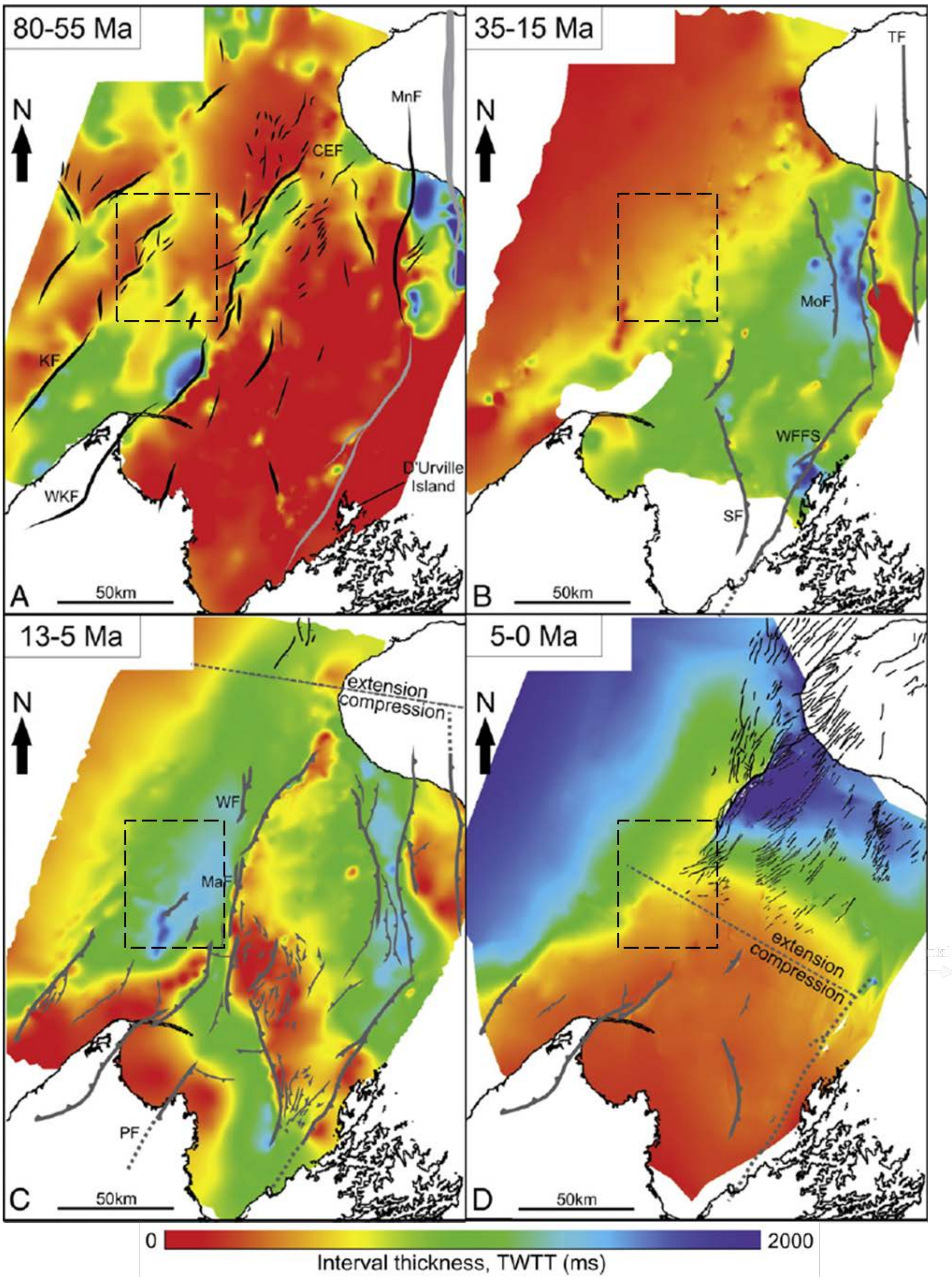



*Figure 2.5 Central and southern Taranaki Basin fault systems and their evolution from basin formation in the Late Cretaceous (A) to the onset of shortening in the east and the extension of compression to more western and southern locations (B and C) through to the onset of back arc basin formation in the north and a resumption of normal faulting (D). Study area is shown as a dashed box. Fault name abbreviations: WKF: Wakamarama Fault; CEF: Cape Egmont Fault; MnF: Manaia Fault; MoF: Motumate Fault; WFFS: Waimea-Flaxmore Fault System; SF: Surville Fault; WF: Whitiki Fault; MaF: Maari Fault; PF: Pikikuruna Fault; KF: Kahurangi Fault. Modified from Reilly et al., 2015.*

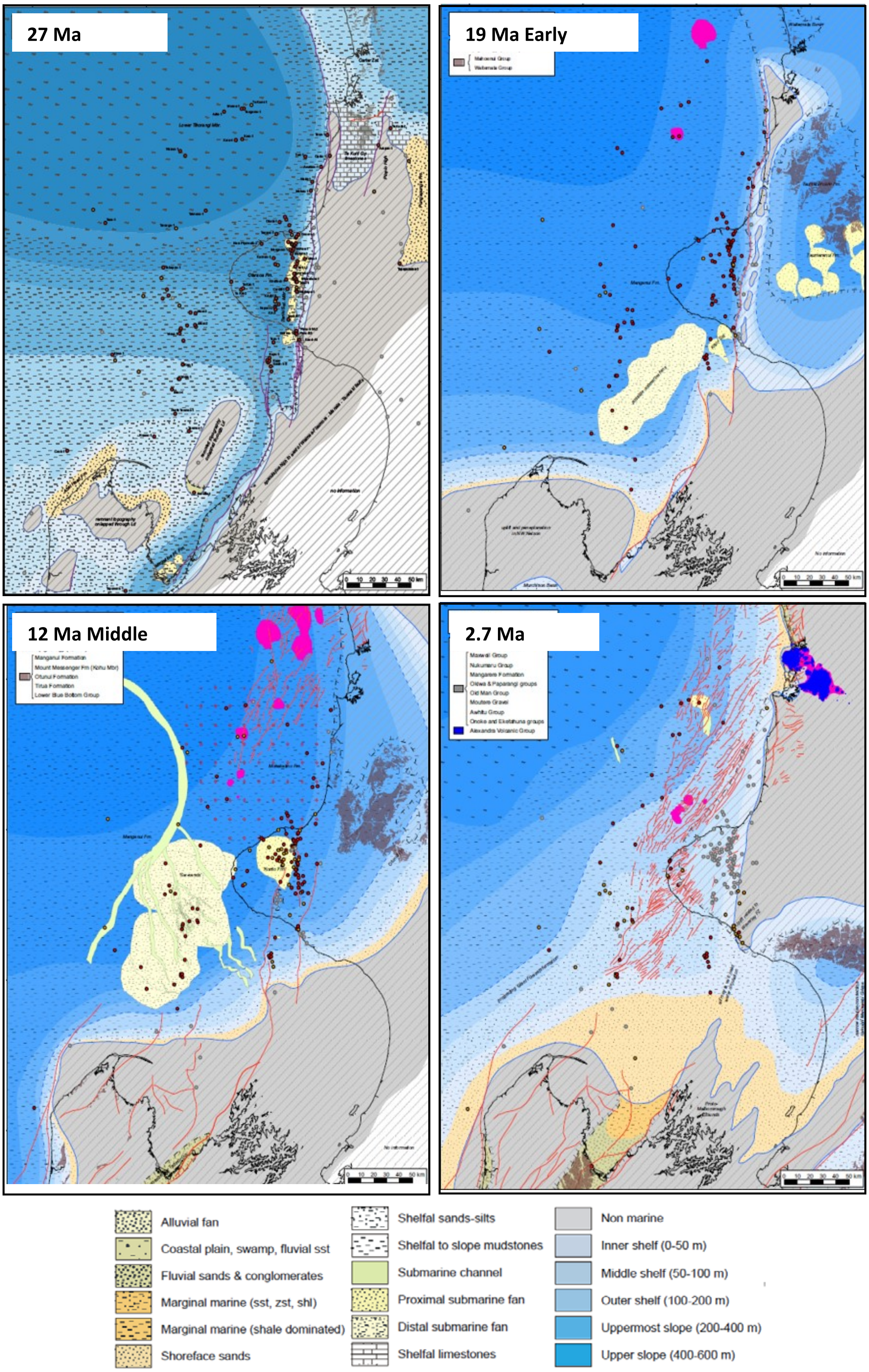



*Figure 2.6 Transition from passive margin phase in Oligocene, establishment of foreland basin in early Miocene and continued regressive sedimentation to present shown. From Strogen (2011).*

## 2.9 North Cape and E Shales

North Cape Shale is the earliest and oldest part of the Turi Formation/Moa Group and occurs as a thin 18-42 metre package of siltstone and claystone in the study area, deposited at the top of the marginal marine/shallow marine North Cape Formation. This implies it is most probably a transgressional deposit. It is therefore the Late Cretaceous flooding event observed elsewhere in the basin. Well results (Romney-1) and interpretation of GNS paleogeography maps (Strogen, 2011) support this scenario.

The E Shale depositional environment is more certain than the North Cape Shale, and has been previously established (in unpublished petroleum reports) as representing a landward incursion of the Turi Formation, a widespread marine transgression into the basin in the Paleocene ([1]NZOP, 2004; [2]NZOP, 2004). This environment resulted in a thick and continuous, fine grained sequence consisting of predominantly claystones capable of forming top seals in the Maui and Tui fields.

## 2.10 Biostratigraphic Ages of North Cape and E Shale

Biostratigraphic dating of the two seals has been carried out by multiple authors using various species types depending on facies. Table 1 shows observed ages from biostratigraphic analysis of both the E Shale and North Cape Shale. Age equivalents of the E Shale were observed in eight wells, with six wells identified as having drilled North Cape Shale or its age equivalent section. Foraminifera and dinoflagellates had been interpreted for marine facies with miospores used to date non-marine sections. Cuttings and core chips from the wells were analysed to count species type, abundance and to interpret age ranges.

***Table 1*** *Recorded ages of the E and North Cape Shales from the examined wells. Lower case "e" and "l" denote early or late age periods.*

| E SHALE | | |
|---|---|---|
| **Well** | **Age** | **Source of data** |
| Amokura-1 | Dt - e Dw | Age from near offset well Tui-1 (PR2784) |
| Matuku-1 | e Dw | PR5021. Biostratigraphy report from Matuku-1 WCR. |
| Hector-1 | Dw | GNS report 2013-311, PR5072 |
| Hochstetter-1 | e Dw | GNS report 2013-311, PR5072 |
| Kiwa-1 | e Dw | GNS report 2013-311, PR5072 |
| Rahi-1 | NA | None acquired |
| Pukeko-1 | l Dw-l Dh | GNS report 2013-311, PR5072 |
| Maui-4 | NA | GNS comp log, PR4512 |

| | | |
|---|---|---|
| Fresne-1 | NA | Section missing in well |
| Whio-1 | e Dw | PR5207 |
| Cape Farewell | NA | Spudded within Farewell Formation. |
| Te Whatu-2 | NA | Dw sediments not reached (PR5072) |
| **NC SHALE** | | |
| **Well Name** | **Age** | **Source of data** |
| Amokura-1 | l Mh | PR2920 |
| Matuku-1 | l Mh | PR5021. Biostratigraphy report from Matuku-1 WCR. |
| Hector-1 | e Dt | GNS report 2013-311, PR5072 |
| Hochstetter-1 | NA | Not reached at well location |
| Kiwa-1 | l Mh-e Dt | GNS report 2013-311, PR5072 |
| Rahi-1 | NA | Not present at well location |
| Pukeko-1 | l Mh-e Dt | GNS report 2013-311, PR5072 |
| Maui-4 | Mh-Dt | GNS comp log, PR4512 |
| Fresne-1 | NA | Not present at well location |
| Whio-1 | NA | Not reached at well location |
| Cape Farewell | Mh-Dt | PR1234. Mh-Dt dated sediments are non-marine |
| Te Whatu-2 | NA | Not reached at well location |

The absolute age of the E Shale in the study area is mainly Waipawan (56-52 Ma), with some scatter towards an older Teurian age (66-56 Ma) and younger (Heretaungan to Porongan ages, 48.9 – 42.6 Ma). Samples were noted to have a marine depositional environment, with age equivalent sections observed in two proximal wells (Pukeko-1 and Whio-1) which were deposited contemporaneously in a terrestrial/marginal marine environment. Age disagreements between authors could be attributed to a number of factors. Sample contamination from cavings can occur when younger material from further up the wellbore becomes mixed with drill cuttings at the bit[2]; reworking of older material is common during deposition, especially where hinterland erosion is widespread; depositional environment may not be conducive to preservation of fossils; post-deposition alteration may damage fossil assemblages; changes in analytical methodologies used to date the samples can differ as the dating techniques and key species are refined over time; and the absolute age of index species can change over time as the global or local time scale is adjusted. Another explanation in this case is that the E Shale may be marginally older in the north and west in the studied wells as this is the probable direction of the marine transgression.

[2] Cavings influence is much reduced through acquisition of core or sidewall core samples for biostratigraphy samples, and consequently in this study data obtained from analysis of core and sidewall core samples was treated with greater confidence than cuttings samples.

North Cape Shale penetrations are sparse within wells in close proximity to the study area and also over the wider basin with wider uncertainty on given ages. Within near-offset wells the North Cape Shale is interpreted as Latest Haumurian (72.1 – 66 Ma) despite some samples placing it as early Teurian (Hector-1). In the most distal well drilled in the basin to date, Romney-1 North Cape Shale is dated as Late Haumurian (83.6-66 Ma). If the same depositional pattern as the E Shale is accepted as valid and appropriate for the North Cape Shale, an age of Latest Haumurian (66 Ma) is expected within the study area with the formation becoming progressively older distally towards Romney-1.

## 2.11 Transgressive Depositional Model

Sequence stratigraphy is the study of depositional patterns during periods of rising and falling relative sea level and the features they leave preserved in the sedimentary record (Vail et al., 1977; Van Wagoner et al., 1988). Transgressive marine deposits are a small part of a larger depositional framework. The following describes some of the key processes and features of transgressive marine deposits which are necessary to understand when interpreting well and seismic information in the following chapters.

Transgressive deposition by definition is the accumulation of sediments during a relative rise in sea level with inland retreat of the coastline. Causes of transgression can be basin subsidence such as a rifting event, changes from glacial to interglacial periods affecting global sea level, or a sharp reduction in sedimentation rates. Preservation in the sedimentary record is common and, while this work focuses on marine transgressive sequences, it is important to consider the effects of transgression elsewhere in the landward direction where it can be represented by the shoreline, paleosols, coal measures and lagoonal/estuarine facies types (Cattaneo and Steel, 2003). Aggradational stacking patterns would be expected in the nearshore deposits, with onlapping stacking patterns in the distal marine areas (Catuneanu, 2002).

A transgressive marine deposit would be expected to have the following features in an ideal preservation scenario with no subsequent reworking or erosion:

- An erosional basal contact, termed a “ravinement surface” (RS1) where tidal/wave action has eroded part of the underlying sequence as the shoreline moved inland. Commonly, these may erode into coal measures which mark the beginning of the transgressional cycle which is now overrun by the sea.

- A section of tide dominated sand prone facies immediately overlying the initial ravinement surface, as shoreline and beach sands move landwards, followed by a further ravinement surface termed the "wave ravinement surface" (RS2) as water levels deepen.
- A transgressive lag deposit (tL) overlying the ravinement surface. These are thin (0.5 - 2.0 metre) deposits characterised by coarse sediments, shell hash or glauconite-rich zones and are commonly bioturbated (Cattaneo and Steel, 2003).
- A deepening upwards sedimentary trend above the tL changing from silts into fine clays and marls as water depth increases.
- A zone of maximum flooding which is the point at which the overlying water column reaches its maximum depth (the maximum flooding surface or "MFS"). Gamma ray logs should show a gradual increase of gamma levels from the base of the transgressive package towards this maximum flooding surface, at which point it should show a peak zone with elevated readings due to higher concentrations of radioactive clays.
- Gamma signatures should decrease above the MFS as sedimentation moves from transgressive back to regressive patterns and relative sea level begins to fall. Increased coarser sediments will begin to be deposited again as relative sea level drops and sediments trapped on the shelf are remobilised to deeper water areas.

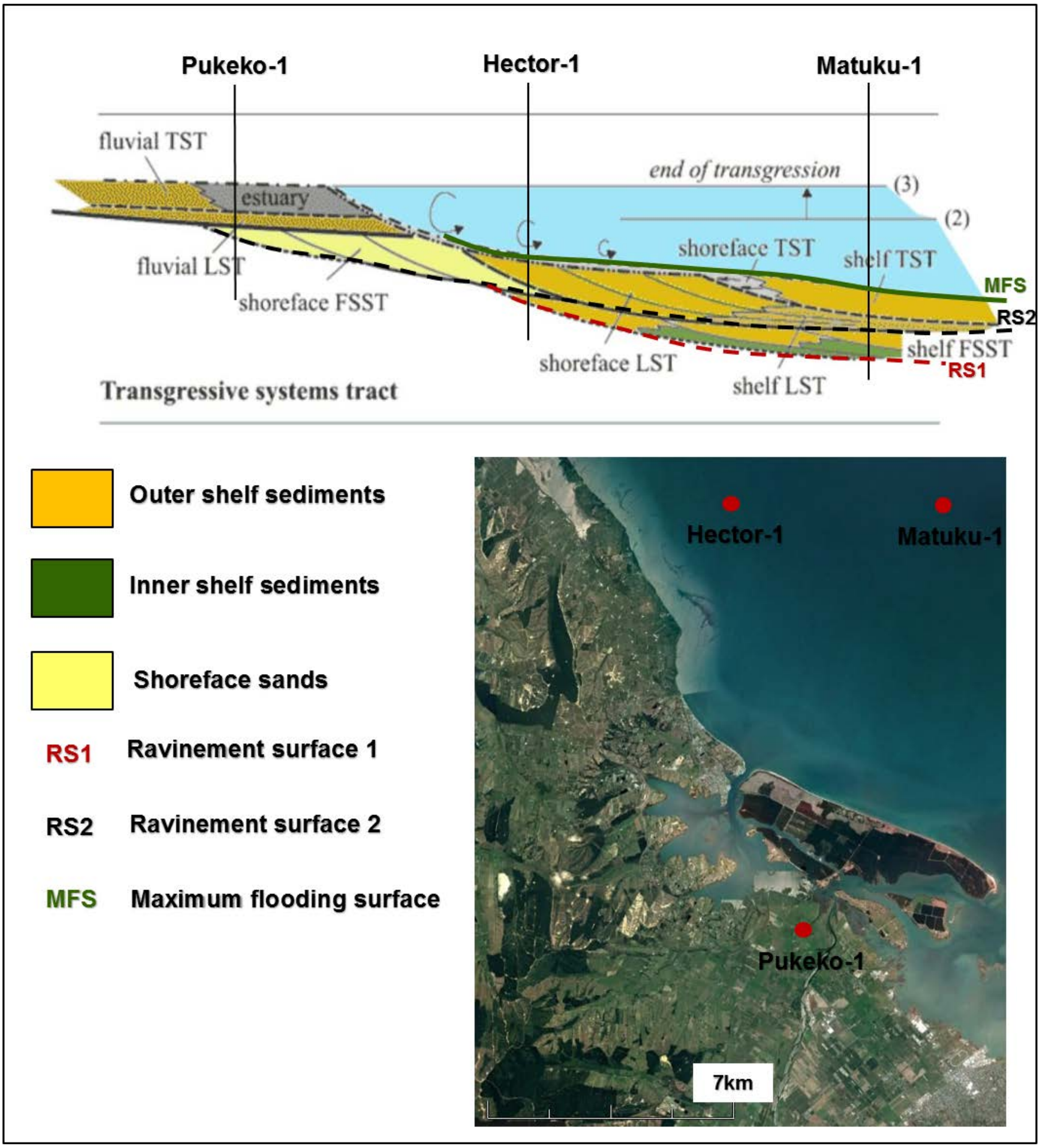



*Figure 2.7 E Shale transgressive depositional model with key surfaces superimposed. Lower inset is an analogue depositional environment at Mapua, Nelson. Modified from Catuneanu (2002).*

# 3. Seal Rocks

## 3.1 Introduction

Seals are an important feature of every hydrocarbon accumulation as they represent a barrier to migrating fluids (Figure 3.1). These seals are generally relatively thick (177m, Tui Field), laterally continuous and homogenous low permeability layers of sedimentary rock that lack significant fractures and faults (Downey, 1984). Effective seals also require a favourable geometry and capacity to hold back columns of fluid (Norollah et al., 2015). Seal rocks can comprise of any rock type (Sneider, 1987) but common seals in New Zealand are claystones. Fine grained sediments make up a significant proportion of the Cretaceous to Neogene rocks in New Zealand sedimentary basins. For example, in the Taranaki Basin they make up between 60-70% of sedimentary fill (Darby, 2002).

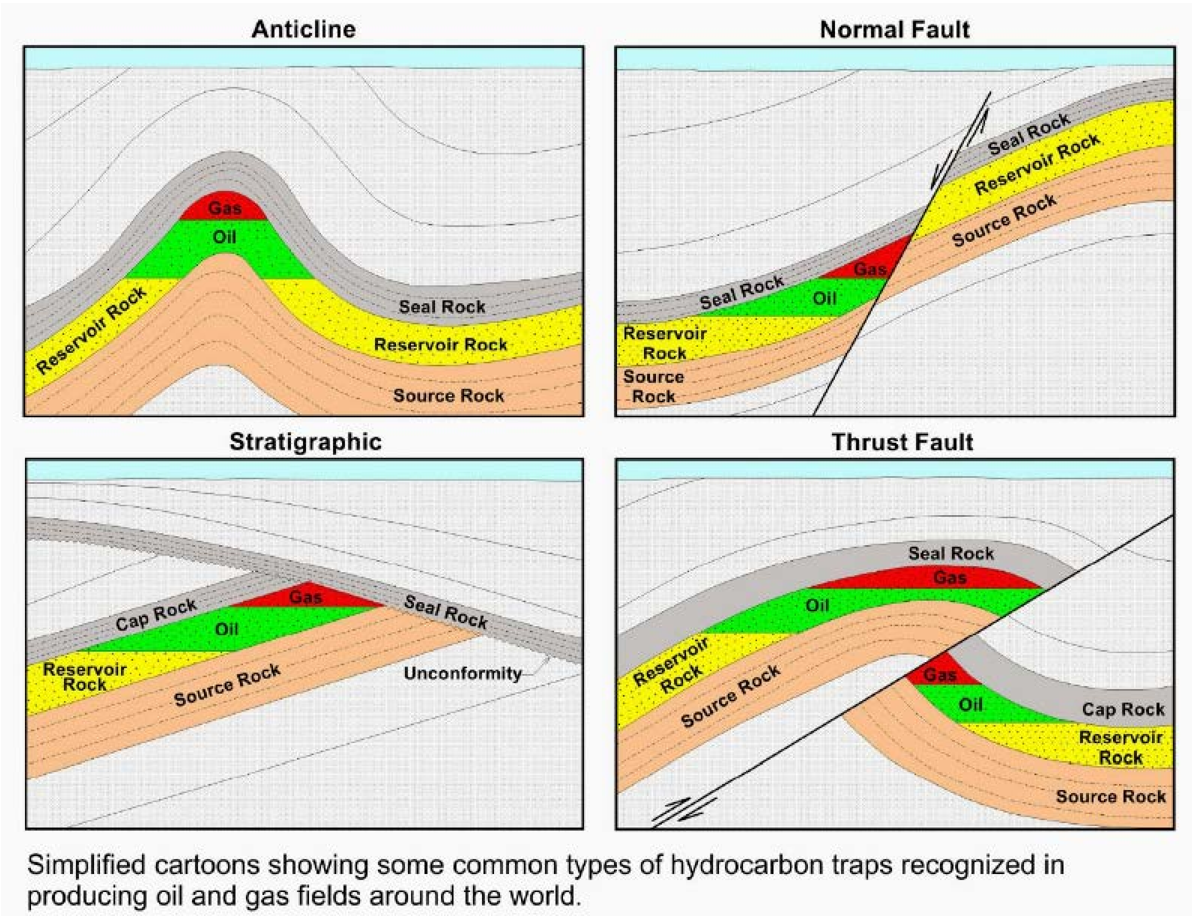



*Figure 3.1 Seals forming hydrocarbon traps. From Geology In (2014).*

Claystone is a rock that is, typically defined as a hard, finely laminated, sedimentary rock composed primarily of clay, mud and silt. This definition does not describe mineralogy but rather the grain size, which consist of clay sized particles with grain sizes of 2 µm or less (Drever, 1997; Boggs, 2001; Spooner, 2014). While claystone refers to the grain size, care must be taken not to confuse the term with clay minerals, which are a group of hydrous silicates often found within claystones.

Taranaki claystones predominantly consist of a mixture of quartz, feldspar, lithics, clay minerals and organic material (Larmer, 1998). Observations of the discovered fields to date indicate that the most effective seal rocks in the Taranaki Basin are claystones deposited in marine environments. The three major claystone top seals for the majority of the hydrocarbons discovered to date are the Latest Cretaceous to Eocene aged Turi Formation, the Oligocene Otaraoa Formation and the Miocene Manganui Formation. This study focuses on two proximal members of the Turi Formation - the North Cape Shale and E Shale that have been unsuccessful to date in demonstrating an ability to hold hydrocarbon accumulations in the Southern Taranaki Basin, and assesses the permeability and distribution spatial distribution of these potential seals.

Turi Formation is an extensive regional unit that has been encountered throughout the basin. While there is no surface outcrop, petroleum drill holes have shown it to exceed 800 metres thick in the Northern Taranaki Graben (Shell, BP & Todd, 1975) and is typically < 200 meters thick in the Southern Inversion Zone. Its age ranges from Latest Cretaceous in Romney-1 (North Cape Shale equivalent) to Latest Eocene (Anadarko NZ Ltd, 2015; King and Thrasher, 1996). It is a second order stratigraphic transgressive unit (Figure 2.3) and forms a seal over the fluvial to marine clastic reservoirs of the North Cape Formation (no discoveries), Farewell Formation (Tui Area, Kupe and Maui B fields), Kaimiro Formation (Maui A and B, Kaimiro, Mangahewa and Turangi fields) and Mangahewa Formation (Maui A and B, Manaia, Maari, Kapuni, Mangahewa and Pohokura fields). These accumulations contain the majority of reserves discovered in the Taranaki Basin to date: 7 TCF of gas and 500 MMbbls of oil and condensate (MBIE Energy Data File, 2016).

## 3.2 Previous Research on the Influences on Seal Quality

Hydrocarbons expelled from a source rock migrate either towards the surface or to areas of lower pressure through any available interconnected pore spaces large enough to permit movement. This is due to the hydrocarbon's lower relative density (0.1- 0.5 S.G for gas; 0.5-1.0 for oil) compared to the surrounding subsurface pore fluid which is normally brackish to highly saline water (1.0-1.2 S.G) (Vara et al., 1992). This migration continues until the hydrocarbons reach a barrier or seal.

Effective seals that trap hydrocarbon accumulations are rocks with capillary entry pressures sufficiently high to prevent large volumes of fluid passing through them (Downey, 1984). Evaluation of the effectiveness of these seals typically takes place at the micro scale from samples acquired at outcrops and in petroleum wells. While it is tempting to extrapolate analogues from point sample datasets to represent seal properties over regional areas, this approach needs to be treated with caution due to the observed highly variable permeability of seal rocks over short distances, sometimes as little as one metre (Sutton et al., 2004; Dawson and Almon, 2006).

Cap rock seals can be split into two divisions: those that fail by capillary leakage (membrane seals), which are the most common type observed in the Taranaki Basin to date, or hydraulic seals that are so strong that no feasibly trapped hydrocarbon column is able to breach them (Watts, 1987). For membrane seals, the sealing layer *thickness* is not an indicator of good seal potential as increasing the thickness does not enhance membrane seal capacity. The major control is the capillary entry pressure, which remains unaffected by seal thickness (Watts, 1987). In other words, once a membrane seal has enough pressure from a hydrocarbon column acting against it, the fluids will start migrating through regardless if it is one meter or 100 meters thick. Hydraulic seals require a fracture in order for hydrocarbons to totally penetrate through and therefore show a direct relationship between seal thickness and competency as an increased seal thickness would reduce the likelihood of faults or fractures penetrating their entire thickness (Sluijk and Parker, 1986; Watts, 1987).

Sneider et al. (1997) and Sneider and Sneider (2002) performed a detailed analysis on the capacity of seals to withhold hydrocarbons based on mercury injection capillary (MICP) tests of core and cutting samples and then ranked the seals based of their capacity to withhold pressure (Table 2). Dominant controls on sealing capacity were observed to be pore size distribution, claystone ductility, lateral continuity and the type of fluid that the seals were holding back.

Studies carried out by Sutton et al. (2004) on the controls of sealing capacity in Cretaceous marine shales showed that bioturbation and large pore throat size in shales were detrimental to seal quality. Parallel alignment of organic matter with bedding planes and high amounts of organic matter were shown to have a positive impact on seal quality through MICP testing. Interestingly, an increase in silt content did not appear to degrade seal effectiveness and increases in sample cementation did not appear to be indicative of enhanced seal quality. The highest quality seals were found to occur in transgressive systems either within or just below condensed sections (maximum flooding surfaces) where the median pore throat size between grains was smallest. The work of Sutton et al. (2004) also showed that at outcrop scale, seal withholding capacity varied significantly, even in adjacent samples.

Dawson and Almon (2004) characterised eight major claystone types from deep marine depositional settings in the Gulf of Mexico and noted that good seal quality as measured by highly pressured MICP values was most common in samples with a silt content < 20%. Cementation and lamination parallel to bedding increased entry pressures. Bioturbation was mostly detrimental to sealing capacity due to the disruption of grain alignment with bedding. The highest seal quality was measured in transgressive claystones and the poorest seals occurred in lowstand deposits.

Larmer (1998) conducted a compositional evaluation of sealing claystones on Late Cretaceous to Pliocene aged rocks in outcrops and petroleum exploration wells in the Taranaki Basin. Seals from the Late Cretaceous and Eocene were shown through x-ray diffraction (XRD) measurement to be dominated by kaolinite clay minerals, with subordinate illite and lesser degrees of chlorite and smectite. Acidic environments coupled with the availability of organic carbon from a nearby stable landmass was thought be conducive to kaolinite's predominance as the major clay mineral.

***Table 2*** *Classification of seals based on mercury injection capillary pressure. After Sneider et al., 1997.*

| SEAL CLASSIFICATION ACCORDING TO CAPILLARY PRESSURE | | |
|---|---|---|
| **SEAL TYPE** | **OIL COLUMN HEIGHT ABLE TO BE WITHHELD (m)** | **CAPILLARY PRESSURE @ 7.5% SATURATION (psi)** |
| A* | > 1500 | > 6795 |
| A | 300 - 1500 | > 1359 - 6795 |
| B | 150 - 300 | > 680 - 1359 |
| C | 30 - 150 | > 136 - 680 |
| D | 15 - 30 | > 68 - 136 |
| E | < 15 | < 68 |
| F | Waste zone rock - not effective seal or reservoir | Non-effective seal |

### 3.2.1 *Mercury Injection Capillary Testing and Capillary Pressure*

Laboratory analysis is used to quantify the effectiveness of seal capacity by measuring the entry pressure in claystone via the injection of liquid mercury into the interconnected pores (capillaries) under increasing pressure until it partially saturates the rock and begins to migrate through. Measurements are performed by injecting liquid mercury into an air-dried sample under pressure conditions simulating the sample's recovered burial depth. The sample is normally taken from a core plug or outcrop exposure although drill cuttings can be used in some cases. The magnitude of pressure required to displace the air from the capillary spaces beyond the critical point (normally between 7-10%) is termed the "threshold pressure" and is determined to be the point at which a seal has “failed”. Beyond the threshold pressure, a pathway of interconnected non-wetting fluids is established, allowing migration through the seal. Median pore throat size can be calculated following this analysis by graphing the pressures from zero to 100% mercury saturation of the pore space, as each pressure increase during the test is related to a certain pore size distribution being saturated (largest pore spaces to smallest). High entry pressures are common with seal rocks due to the small pore throats; consistently high readings throughout a vertical claystone section are indicative of good seal potential. The “air-mercury” system is converted to “brine-oil” and “brine-gas” mathematically through consideration of viscosity, capillary pressure, interfacial tension and contact angle for the expected wetting and non-wetting phases in the reservoir (Watts, 1987; Brown, 2003).

Vara et al. (1992) define capillary pressure as the amount of extra pressure required to force the non-wetting fluid phase to displace the wetting phase in the capillary space. During burial, all sedimentary rocks are exposed to water at some point. As a result, individual grains are typically water-wet as the water forms an adhesive bond (solid – liquid) around the grain. The interconnected pore spaces between the framework grains (the capillaries) are filled with water or hydrocarbons, which form a cohesive bond with each other (liquid – liquid). If the adhesive force is greater than the cohesive force, the fluid is defined as “wetting”; that fluid will adhere to the grain’s surface (Figure 3.2). If cohesive forces exceed adhesive force, the liquid is defined as “non-wetting” and the fluid will only occupy the capillary pore spaces. Hydrocarbons normally fall into the non-wetting phase as they are able to displace the water from capillaries given sufficient injection pressure but do not displace the initial water coating the grain. This makes mercury injection capillary testing an excellent way to simulate the behaviour of hydrocarbons within a reservoir and test the hydrocarbon column height a given seal is capable of withholding.

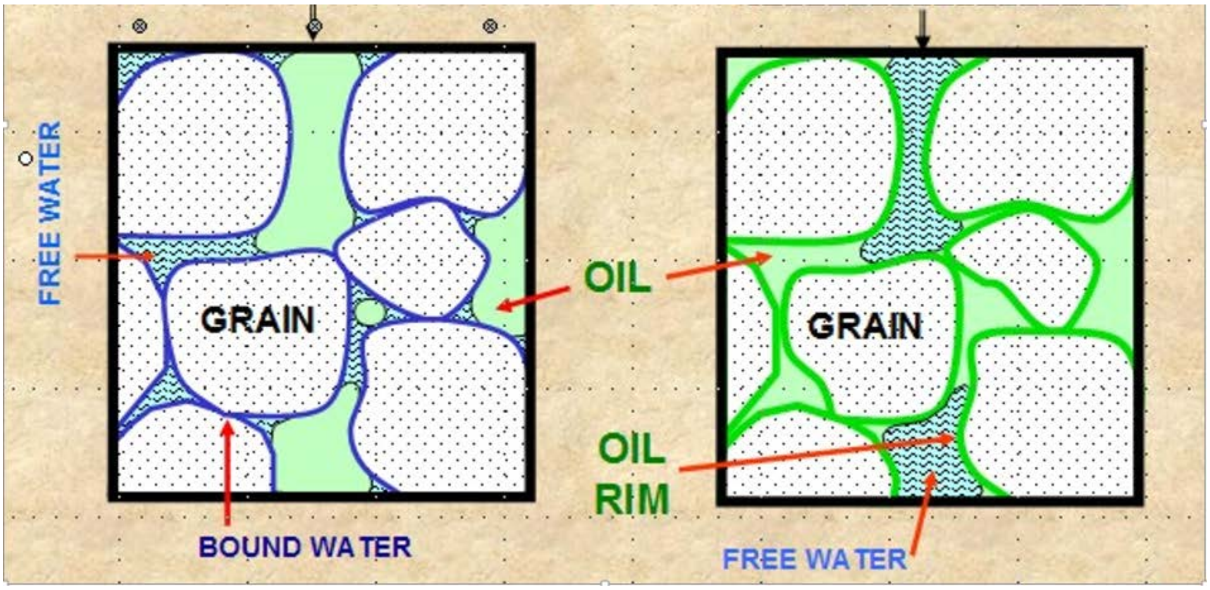



*Figure 3.2 Diagrammatic representation of wetting phase. Panel (A): water as the wetting fluid surrounding the grains, with oil as a non-wetting fluid in the capillary spaces together with interstitial water; and (B): oil as the wetting fluid with water contained in the capillaries as a non-wetting fluid. From Crain (2017).*

### *3.2.2 Clay Minerals and Their Effect on Seal Rocks*

Claystones were described previously as commonly containing quartz, feldspar, lithics and organic matter. These minerals are defined as the framework grains in claystones. Clay minerals make up the majority of the rest of the claystone, filling voids between the framework grains. They are of particular importance for hydrocarbon reservoirs as they can adversely affect production by coating grains, thereby reducing porosity, and pore throat sizes, which collectively decrease permeability. The four clay minerals commonly found in the Taranaki Basin are illite, kaolinite, smectite and chlorite (Table 3). Each has a common chemistry in that they are hydrous silicates with layered structures and are found as detrital clays present at the time of burial, or authigenic clays that postdate the deposition of the rock forming in situ (Larmer, 1998). Individual clay minerals are often too fine to be identified visually by petrographic microscope and require analysis by x-ray diffraction (XRD) or scanning electron microscope to confirm their presence (Hillier, 2003).

Illites are micaceous minerals most closely resembling the platy mineral muscovite in igneous rocks. They are formed by the weathering of silicate rocks, most commonly feldspars, in alkaline conditions. They contain high levels of potassium and aluminium and are stable up to 500°C. In the Taranaki Basin, illite has formed from muscovite, feldspars, kaolinite and smectite with increasing burial depth and temperature (Larmer, 1998). As an authigenic clay, it reduces pore size and permeability by blocking pore throats and lining framework grains.

*Table 3 Chemical composition of the major clay minerals*

| GROUP | COMPOSITION | SPECIES | EFFECTS | SURFACE AREA |
|---|---|---|---|---|
| **Kaolinite** | $Al_2Si_2O_5(OH)_4$ | Kaolinite<br>Dickite<br>Nacrite<br>Hallyosite | Reduced porosity. Able to migrate through pore spaces (potential to block pores in producing reservoirs) | 23m2 /gm |
| **Illite** | $[K(Al,Mg,Fe)_2(Si,Al)_4O_{10}[(OH)_2,(H_2O)]$ | Illite | Reduced porosity. Able to migrate during production. | 113 m2 /gm |
| **Smectite** | ((Al, Mg)8(Si4O10)12H2O) | Montmorillonite<br>Beidelllite<br>Hectorite | Sensitive to fresh water (swelling clay). Reduces porosity. | 752m2 /gm |
| **Chlorite** | $(Mg,Fe)_3(Si,Al)_4O_{10}(OH)_2\cdot(Mg,Fe)_3(OH)_6$ | Amesite<br>Greenalite<br>Chamosite<br>Penninite | Reduces porosity. Sensitive to acid (HCl) which form ferric oxide - pore blocking precipitate | 42m2 /gm |

Kaolinite forms predominantly from weathered feldspars and micas (biotite and muscovite) but can also form from illite and smectite under the right conditions with acidic water and high levels of organic matter - creating a pore filling authigenic clay. Larmer (1998) showed kaolinite to be the predominant clay type in Cretaceous to Eocene aged claystones in Taranaki. It is stable to temperatures of up to 150$^o$C after which it breaks down to form other clay minerals such as illite. Kaolinite tends to be less dominant in entirely marine environments of deposition where chlorite and smectite become the more common authigenic clays as the availability of calcium allows them to form preferentially.

Smectite forms from weathering of basic (low silica content) rocks and tephras in environments with a high proportion of calcium and low levels of potassium. In Smale (1996), chlorite was recognised to form from biotite, chlorite and smectite. It represents a minor component of the clay minerals of Cretaceous to Eocene age in the Taranaki Basin but is prevalent in other New Zealand basins of a similar age such as the East Coast Basin.

Larmer (1998) noted that most clay minerals in the Taranaki Basin claystones were likely to be of detrital rather than authigenic origin since the reduced permeability of claystones compared to reservoirs would not be conducive to the fluid movement required to form authigenic clays. Reservoir sandstones are better able to transmit fluids and are therefore more susceptible to authigenic clay formation.

## 3.3 North Cape Shale Properties

North Cape Shale was encountered in three of the four wells drilled within the study area (Table 4) and ranges in thickness from 42 to 18m. Thickness was also measured in offset wells in order to form a more regional picture of its spatial distribution. In the Matuku-1 well North Cape Shale is 71 m thick which is considerably thicker than the next thickest interval at Pukeko-1 (42 metres); these thickness variations are consistent with distal trends in thickness observed for the E Shale (section 3.4).

Cores recovered from the wells studied are typically dominated by sandstones because the reservoir sections are preferentially sampled during the exploration phase. The only North Cape Shale sample from Hector-1 is a laminated siltstone with traces of fine sand and glauconite (Figure 3.3). The single Pukeko-1 sample, also from the base of the unit, is a similar laminated siltstone with fine sand. Matuku-1 provides the most comprehensive North Cape Shale dataset to date, with six sidewall cores recovered from this well (Figure 3.3). Uppermost samples from Matuku-1 are described as hard brownish grey siltstone with laminations and traces of fine sandstone (Figure 3.3). At the base of the unit, the sand content increases and is accompanied by silt, carbonaceous material and glauconite.  Descriptions of drill cuttings of the North Cape Shale indicate that it as predominantly grey-brown siltstone with finer clay rich intervals, non-calcareous for the most part, with common to rare carbonaceous material, laminations varying from clay to fine sand and common traces of glauconite, particularly towards the base of the unit.

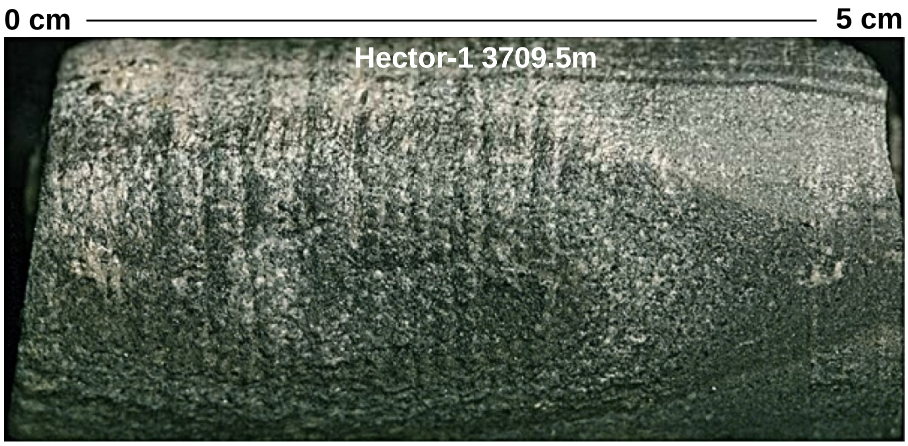
Sample compositions analysed by XRD analysis were available from NZPAM unpublished petroleum reports for three samples of the North Cape Shale (from Matuku-1 and Hector-1), with an additional composition estimate from point counts (Appendix 1). Unlike the study carried out by Larmer (1998), the clay constituents are not dominated by kaolinite, with illite/mica making up the majority of the clay components, followed by chlorite.  Mercury injection data, also from NZPAM unpublished petroleum reports, was only available for two samples within the North Cape Shale, both from Matuku-1, and are shown in Appendix 2. Seal quality was good to excellent (Sneider seal class B and A), with the A class result derived from a sample described as a sandy siltstone (Figure 3.4). Parallel laminated bedding visible in the core's cross section could be responsible for the high entry pressures of this sample and, if so, is encouraging as similar laminations are clearly visible in the Pukeko-1 cores from within the study area (Figure 3.3).

*Table 4 Thicknesses of seal packages in wells taken from NZPAM unpublished petroleum reports*

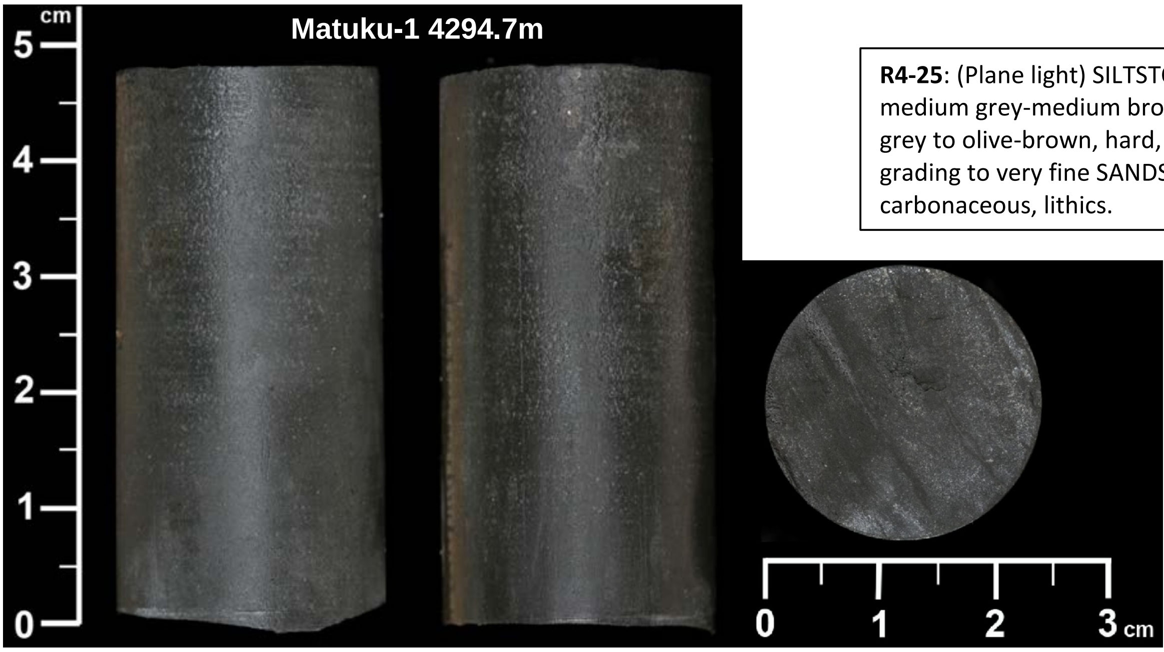
| E SHALE | | | | |
|---|---|---|---|---|
| **Well** | **Top (m MD)** | **Base (m MD)** | **Thickness** | **COMMENT** |
| Amokura-1 | 3497 | 3674 | 177 | |
| Matuku-1 | 3728.5 | 3936 | 207.5 | |
| Hector-1* | 3385 | 3455.4 | 70.4 | |
| Hochstetter-1 | 3076 | 3202 | 126 | |
| Kiwa-1* | 3358.5 | 3425 | 66.5 | |
| Rahi-1 | 3317 | 3391 | 74 | Includes sandy section ("E" sands) |
| Pukeko-1* | 3555 | 3658 | 103 | |
| Maui-4 | 2253 | 2266 | 13 | Possible proximal equivalent |
| Fresne-1 | 0 | 0 | 0 | Section removed or is non-marine |
| Whio-1 | 2606 | 2670 | 64 | Misleading thickness - interbedded with multiple sandy packages |
| Cape Farewell | 0 | 0 | 0 | Section removed or is non-marine |
| Te Whatu-2* | 0 | 0 | 0 | Below TD of well |
| **NC SHALE** | | | | |
| **Well** | **Top (m MD)** | **Base (m MD)** | **Thickness** | |
| Amokura-1 | 3935 | 3977 | 42 | |
| Matuku-1 | 4261.5 | 4332.5 | 71 | |
| Hector-1* | 3684 | 3709.9 | 25.9 | |
| Hochstetter-1 | 0 | 0 | 0 | Below TD of well |
| Kiwa-1* | 3680 | 3698 | 18 | |
| Rahi-1 | 0 | 0 | 0 | Section not preserved |
| Pukeko-1* | 4018 | 4060 | 42 | |
| Maui-4 | 2820 | 2880 | 60 | Uncertain if actually present in this well/proximal equivalent |
| Fresne-1 | 0 | 0 | 0 | Section is non-marine |
| Whio-1 | 0 | 0 | 0 | Below TD of well |
| Cape Farewell | 0 | 0 | 0 | Section is non-marine |
| Te Whatu-2* | 0 | 0 | 0 | Below TD of well |

* denotes wells within the study area


SWC 8: (Plane light) Interlaminated SANDSTONE and SIL TSTONE medium dark grey sandstone, hard, well sorted with common dark greenish grey subrounded lithics, non-calcareous, no visible porosity. Dark brownish grey siltstone, micaceous. No fluorescence.




**SW1** SILTSTONE: (80%) (UV Light) brownish black, very hard, 1-3 cm thick laminations, non-calcareous, abundant biotite
SANDSTONE: (20%) greenish grey, hard, very fine upper to fine lower, well sorted, angular to subrounded, non-calcareous cement, minor glauconite, 0.5-2 cm thick laminations.




**R4-25**: (Plane light) SILTSTONE: medium grey-medium brown, olive-grey to olive-brown, hard, very sandy grading to very fine SANDSTONE, carbonaceous, lithics.

*Figure 3.3 Sidewall cores of the North Cape Shale recovered from Pukeko-1, Hector-1 and Matuku-1. Note laminar bedding visible in all three samples as darker layers. Pictures sourced from NZPAM unpublished petroleum reports.*

## 3.4 E Shale Properties

The E Shale has been encountered in two wells drilled below the Miocene horizon within the study area (Table 4). It ranges in thickness from 66 to 70m, with the section at Pukeko-1 either eroded or replaced by a proximal equivalent paralic coal measure sequence. Offset wells outside the study area such as Amokura-1, Hochstetter-1 and Matuku-1 show an increase in the thickness of the E Shale to > 100m in a northwest or distal direction. Whereas in the south-eastern proximal direction, Whio-1 and Maui-4 show negligible thicknesses and are represented by time equivalent sections of paralic/coastal plain sediments.

Descriptions of drill cuttings from wells describe the E Shale as predominantly siltstone grading to claystone in the more northern wells (Amokura-1, Matuku-1) transitioning to an interbedded sequence of siltstone/sandstone and coal measures further south in the study area at the Pukeko-1 well location. This is considered an age equivalent section but does not represent the same depositional facies. At Hector-1, it comprises a mixture of sandstone and siltstone, with the siltstone becoming more prevalent towards the base. It is soft to firm, non to slightly calcareous and contains carbonaceous laminae and glauconite. Cored lithologies of E Shale are dominated by claystone in Amokura-1 with glauconite rich bioturbated silts and sands at the basal contact with the Farewell Formation. Matuku-1 recovered five sidewall cores from the E Shale succession of which four were very fine to fine sands and the lowest sample from 3931.8 metres was described as a grey, very hard siltstone with traces of sand and carbonaceous material. Sidewall cores from the base of the E Shale in Hector-1 are of fine laminated sandstone with common glauconite and micas, whereas just below this at the very base of the unit it appears as a glauconite rich siltstone (Figure 3.4).

Whole rock compositions acquired by XRD analysis are available for 11 samples with an additional composition estimate from petrographic thin sections. All of these samples are collated in Appendix 1. Results show that cored samples are rich in quartz and feldspar, with these minerals making up the majority of the framework grains. Kaolinite is the most dominant clay mineral present (six samples), followed by chlorite (three) and illite (two). Interestingly, kaolinite clay dominance was spread over five different wells, with chlorite clay dominance restricted to the two more distal wells, Amokura-1 and Matuku-1. Twelve mercury injection data points were available, with seal quality ranging from poor to excellent. Sneider seal classes range from A to D (Appendix 2).

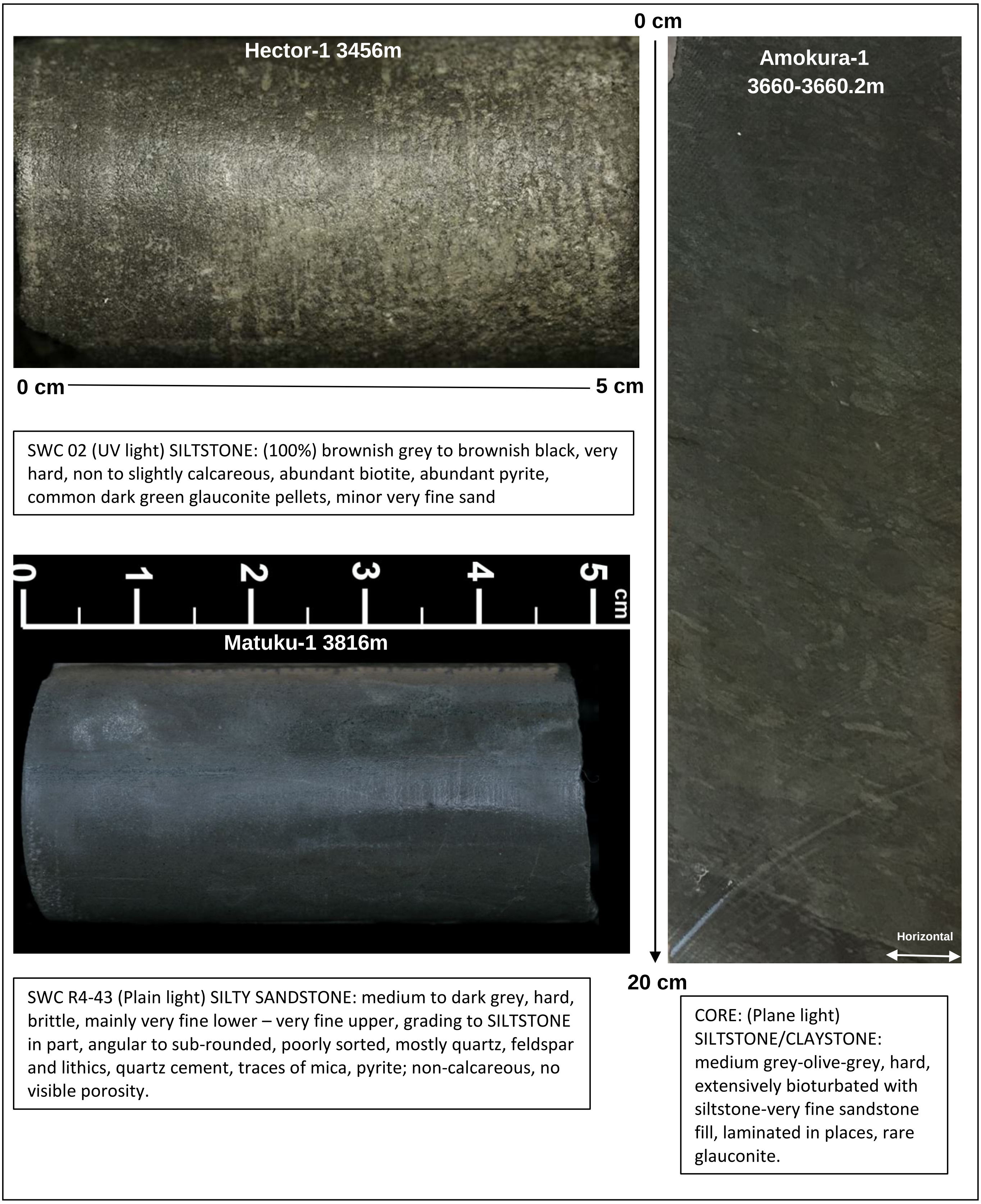



*Figure 3.4 Sidewall cores of the E Shale recovered from Amokura-1, Hector-1 and Matuku-1. Note bioturbation in Amokura-1 core (lighter coloured areas with random alignment) which are fine sand and silt filled burrows. Pictures sourced from NZPAM unpublished petroleum reports.*

## 3.5 Results and Discussion

Multiple factors influence seal rock quality in Taranaki, some of which are consistent with research in other areas of the world. The most comprehensive analytical technique available to test seal quality is MICP testing and the resulting calculations of median pore throat sizes. This study uses mercury injection capillary data and also includes lithology types and petrology results used to assess the quality of seal (and the factors that control the quality). However, it is recognised that the small number of samples available for analysis may not be sufficient to draw detailed conclusions about seal quality or to extrapolate the findings on a regional basis.

A plot of threshold entry pressure versus median pore throat size shows that, while the best A and B Sneider class seals have small median pore throat sizes, other samples which also have small median pore throats are only poor to moderate seals at best (Figure 3.5). Samples with pore throat diameters over 1 um constituted poor seals in all cases. A uniformly small pore throat size appears to be a requirement for better seals but this is only one contributing factor.

Examining the clay proportions of seal samples shows that overall high abundances per sample are ambiguous with enhanced seal properties in any recognisable pattern. A and B quality seals have total clay proportions ranging from 24 to 56% of the total sample, while C to D class seals range from 19 to 43% (Table 5). No single clay mineral type is prevalent across all the studied seal formations, though kaolinite and illite/mica are the most numerous. It is possible that kaolinite was once a more dominant clay type given that alteration of clay minerals can occur with elevated temperatures - changing some of the original kaolinite to illite through diagenesis. Chlorite is present in all samples but is the dominant clay type in only one, which displayed a poor MICP test results. Total clay content above a threshold level of approximately 25%, regardless of clay type, combined with a small average median pore throat size should be indicative of a good seal rock based on these samples prior to confirmation by MICP testing.

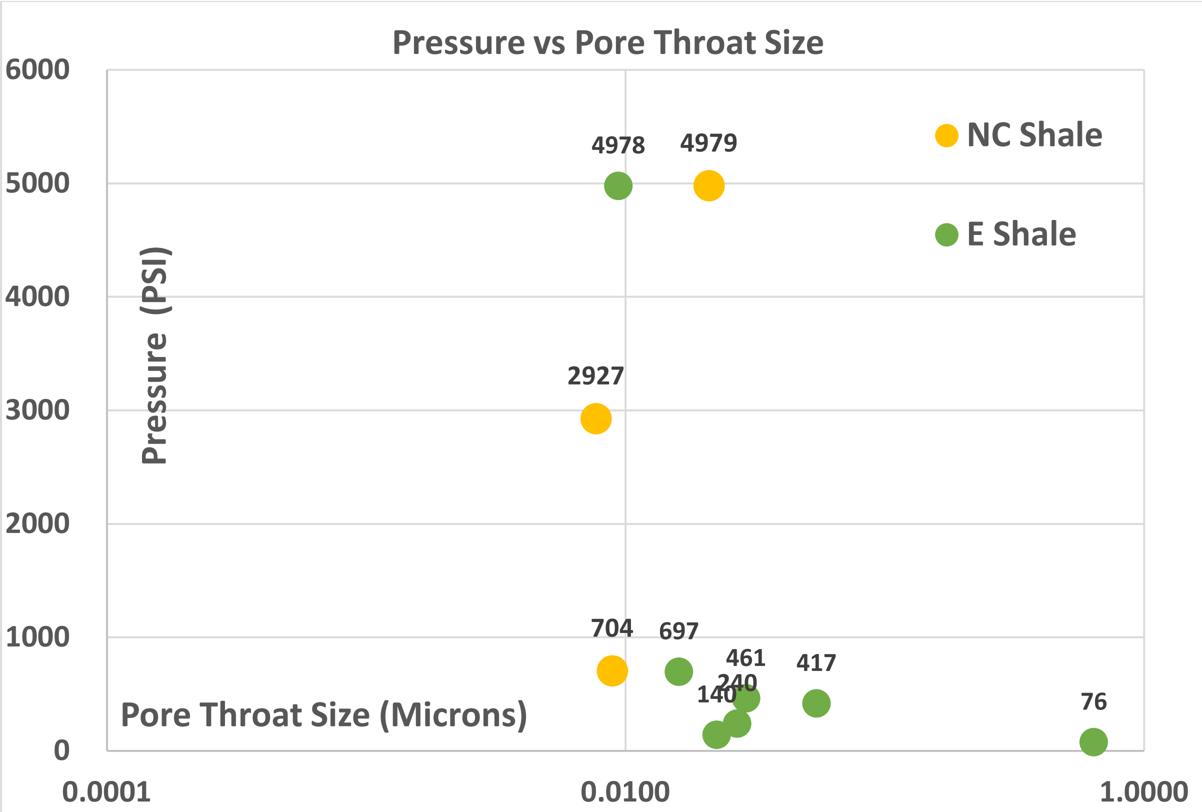



*Figure 3.5 MICP recorded threshold pressures at 7.5% mercury intrusion (point at which seal breach is inferred to occur) vs median pore throat size, plotted for both the North Cape and E Shale samples. E Shale samples from Kiwa-1, Hector-1 and Matuku-1. North Cape Shale samples are from Matuku-1 only. Data sourced from NZPAM unpublished petroleum reports.*

A common characteristic of those seals with favourable properties is the presence of fine laminations and carbonaceous matter in the sidewall core descriptions (Table 5). While these factors might be expected to have only minor effects on seal quality, they are a common element of the A and B class seals and their significance is supported by the work of Sutton et al. (2004). The presence of fine laminations within the claystones is consistent with a low energy depositional environment not overly affected by sediment reworking processes. Therefore, a sample's position within an actively subsiding depocentre is likely to have an important influence on the distribution of better quality seals, with a higher probability of these conditions existing in the deeper water area away from basin margins. This environment would be conducive to preserving a sediment fabric with parallel-aligned fine grained and platy material.

*__Table 5__ Dominant clay types in samples compared with MICP Sneider seal values. Note distribution of "good" seal results (A and B) is not restricted to claystone lithotypes. Data sourced from NZPAM unpublished petroleum reports.*

| Well | Formation | Sneider Class | Lithotype | Laminated? | Clay % in Sample | Dominant Clay Type |
|---|---|---|---|---|---|---|
| Kiwa-1 | E Shale | C | Siltstone | N | 43.2 | Kaolinite |
| Kiwa-1 | E Shale | D | Siltstone | N | 30.9 | Kaolinite |
| Hector-1 | E Shale | C | Sandstone | Y | 34 | Kaolinite |
| Whio-1 | E Shale | A | Claystone | Y | 43.5 | Kaolinite |
| Matuku-1 | E Shale | D | Sandstone | N | 24.6 | Chlorite |
| Matuku-1 | E Shale | A | Claystone | N | 55.8 | Kaolinite |
| Matuku-1 | E Shale | C | Sandstone | N | 19 | Ilite/Mica |
| Matuku-1 | E Shale | C | Claystone | N | 31.5 | Ilite/Mica |
| Matuku-1 | NC Shale | B | Sandstone | Y | 24.2 | Ilite/Mica |
| Matuku-1 | NC Shale | A | Claystone | Y | 30.2 | Ilite/Mica |
| Matuku-1 | NC Shale | C | Sandstone | Y | 30.2 | Ilite/Mica |

While various lithologies make up each of the seal packages - from fine sands to claystone - claystone lithotypes are not always associated with better seals. On initial visual inspection, some of the mixed lithologies such as interbedded clays and sand might be expected to be poor seals. However, their sand zones of probable higher permeability do not appear to diminish the seal quality.

The effect of bioturbation appears to be neither an enhancement nor a negative influence on seal quality in these samples but not enough data is available to fully quantify this. Visual inspection by the author of an entire core taken from Amokura-1 above the discovered oil accumulation suggests that it is extensively bioturbated, yet clearly this bioturbation has not compromised the seal in this location. Additional MICP testing of the Amokura-1 core in combination with additional whole cores would be required to quantify the effects of bioturbation on seal quality in the Taranaki Basin; this analysis was not conducted for the present study.

# 4. Seal Quality Estimates from Petroleum Wells

## 4.1 Introduction

Other than limited core and sidewall core samples, very little direct information is available on the North Cape and E Shales due to an absence of outcrop exposures. This chapter uses information from log data in petroleum exploration wells to interpret the presence or absence of a seal interval, and compare the variability between each of the wells in the wider area. Gamma ray and neutron/density logs were found to be the most informative, with a full list of logs viewed available in Table 6. Results of the interpretation are shown as well correlation panels, composite well logs and tables, which are collectively used to draw conclusions and guide further work on seismic interpretation (Chapter 5). The log data also contributes information for the construction of paleogeographic maps (Chapter 6).

## 4.2 Relevant Wells for Study

Although multiple wells have been drilled in the southernmost Taranaki Basin, not all encountered the pre-Early Eocene seal units or were drilled deep enough to do so (Table 6). This study focuses on wells which contained a transgressive claystone package at the correct stratigraphic position, whereas wells which displayed a non-marine facies at the same interval (e.g. Fresne-1) are only referenced to illustrate how far the confirmed transgressive marine package extends. Analysis was restricted to the eight wells which contained a definitive E Shale and four wells for the North Cape. Appendix 3 provides an overview for all wells reviewed with additional information including pre-drill targets and results.

*Table 6* *Summaries of the wells reviewed in this study and their relevance to the area*

| Well Name | PR Number | Relevance to study |
|---|---|---|
| **Amokura-1** | 2920 | Proven seal for Amokura oil accumulation by E Shale, wireline log coverage, cored of base E shale section |
| **Cape Farewell-1** | 1234 | Confirms no E or North Cape shale in this area of the basin. Age equivalent facies are terrestrial/reservoir rocks |
| **Fresne-1** | 674 | Confirms no E or North Cape shale in this area of the basin; control point for North Cape Formation facies (terrestrial/reservoir rocks) |
| **Hector-1** | 3806 | Drilled E and thin North Cape Shale, wireline logs and sidewall cores obtained |
| **Hochstetter-1** | 2524 | Drilled E Shale, wireline logs and sidewall cores obtained |
| **Kiwa-1** | 880 | Drilled E and thin North Cape Shale, wireline logs and sidewall cores obtained |
| **Matuku-1** | 5021 | Drilled E and North Cape Shale, wireline logs and sidewall cores obtained |
| **Maui-4** | 543 | Drilled E and North Cape Shale equivalents, wireline logs and sidewall cores obtained; control point for E and North Cape facies |
| **Pukeko-1** | 2928 | Drilled E and North Cape Shale equivalents, wireline logs and sidewall cores obtained; control point for E and North Cape facies |
| **Rahi-1** | 2277 | Drilled E Shale, wireline logs obtained; control point for North Cape Shale (absent due to erosion/non-deposition) |
| **Te Whatu-2** | 1345 | Stops short of E Shale; TD may be just above age equivalent facies at base of well |
| **Whio-1** | 5207 | Drilled a very proximal E Shale equivalent, logs and sidewall cores obtained, control point for E Shale facies |

## 4.3 Log Acquisition

During the drilling of petroleum wells it is standard practice to acquire logs of the borehole to ascertain the presence and thickness of any hydrocarbon bearing zones. If the well is dry, the collection of log data may contribute to a future discovery and/or improve understanding of why hydrocarbons were absent. Logs are acquired either during drilling through the use of “logging while drilling” (LWD) tools attached behind the drill bit or immediately following drilling via wireline tools lowered on a steel cable into the well. Both techniques are commonly used together but wireline is preferred for analysis, as currently it provides greater resolution and a wider variety of measurements.

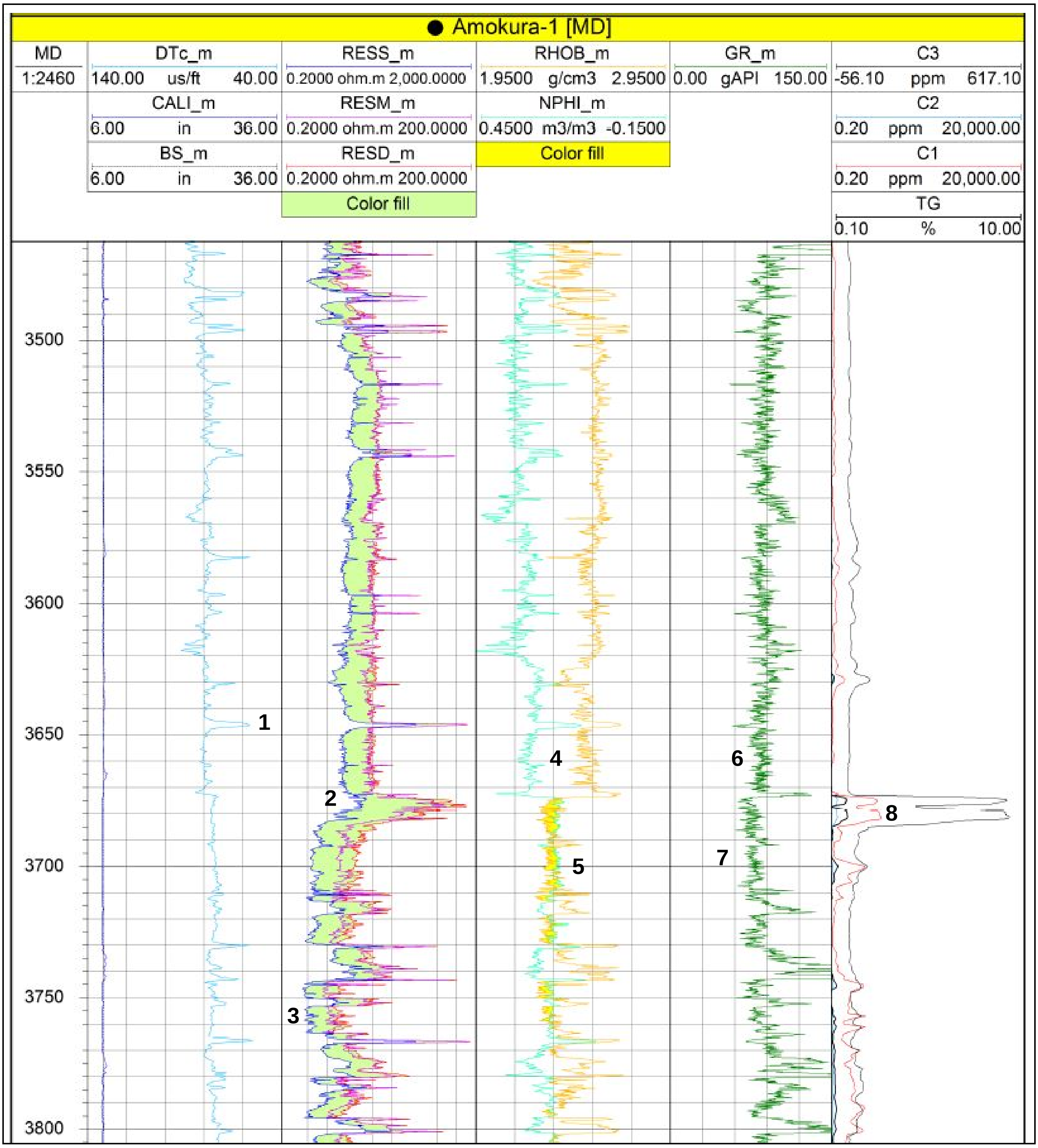



*Figure 4.1 A typical wireline log suite for analysis. Point **1** shows inflection of the sonic curve to the right, indicating a hard zone (limestone/cement bed), **2** and **3** show different resistivities within sandstones with the upper zone containing oil and the lower formation water. **4** and **5** show the usefulness of the neutron and density logs for identifying claystone (curve separation) versus sandy porous zones (cross over). The gamma log (**6** to **7**) shows slight variations between the shale and sand zones, and finally the gas log **8** indicates area that contain hydrocarbon gases.*

Logs from the 12 wells were assessed using Petrel[3] software. Eight of these wells, which had wireline logs available for the intervals including the E and North Cape Shales, were selected for further detailed review. Composite images for these are shown in Appendix 4. The analysis enabled identification of stratigraphic boundaries, thickness measurements, log characteristics such as maximum flooding surfaces and a greater understanding of the depositional environments. A log correlation panel was generated to demonstrate how each of the seal packages varies in thickness and geophysical character regionally (see section 4.5).

## 4.4 Overview of Log Types

Table 7 gives a summary of the basic data types acquired by the various logging tools and their uses. Detection of clay-rich sealing intervals is most commonly performed by analysis of the gamma ray, neutron and density logs, with sonic and resistivity tools complementing these (Figure 4.1). A gamma ray log measures the natural radioactivity in rocks provided by uranium, thorium and potassium which tend to be concentrated in claystones and granitic rocks.

***Table 7*** *Identification and uses of logs acquired in petroleum wells analysed in this study*

| Logging Tool | Abbreviation | Measurement | Common Uses | LWD or Wireline |
|---|---|---|---|---|
| Gamma Ray | GR | Natural radioactivity in rocks | Lithology identifier, mineral types | LWD/Wireline |
| Neutron | NEU/NPHI | Hydrogen levels | Identify pore fluid type, porosity | LWD/Wireline |
| Density | DENS/RHOB | Density of formations | Lithology identifier, porosity | LWD/Wireline |
| Resistivity | RES | Resistance to electrical current | Identify pore fluid type, lithology, permeability | LWD/Wireline |
| Sonic | DT/DTc/DTs | Velocity of sound in formation | Porosity and lithology | LWD/Wireline |
| Spontaneous Potential | SP | Electrical potential | Lithology and permeability | LWD/Wireline |
| Photo Electric Factor | PE | Photoelectric absorbtion | Lithology identifier, mineral types | LWD/Wireline |
| Formation Micro Imager | FMI | Resistance to electrical current | Lithology and sedimentary features; image log | Wireline |
| Caliper | CALI | Borehole diameter | Sense check for logs; borehole quality indicator | LWD/Wireline |
| Mud Gas | TG, C1-C5 gases, H2S | Total gas level, types of gas | Detect hydrocarbons, monitor overpressure & hazards | Surface measurement |
| Rate of Penetration | ROP | Drilling speed | Differentiate soft vs hard formations | Surface measurement |

[3] Petrel is a trademarked Schlumberger software package

Density measurements are obtained by the emission of gamma rays from the logging tool into the formation from a radioactive source, with the resulting effects measured. The signals from emitted gamma rays colliding with electrons in the formation are recorded as they glance off other particles in the wellbore. These collisions cause the gamma rays to lose energy and emit a specific type of radiation called "Compton scatter". The intensity of this radiation depends on the formation's electron density, which is proportional to the atomic weight of the impacted atoms and bulk density of the formation (Bowen, 2003).

The neutron tool works on a similar principle to density. Neutrons are emitted and subsequent collisions with the formation result in gamma radiation when the neutrons are absorbed. Neutrons, however, lose the most energy when impacting an object of equal mass, such as hydrogen atoms. A high hydrogen content is indicative of high water levels or hydrocarbons – resulting in the tool giving low readings over hydrogen-rich zones (Bowen, 2003). This is termed "neutron porosity" as only water or hydrocarbons tend to occupy pore spaces.

These three log types (gamma, neutron and density) are normally sufficient to evaluate the claystone content of potential seals; however, it is standard practice to utilise all of the tools for analytical work in combination with LWD data as variations in lithology, hole condition and drilling mud can all cause misinterpretations of the values.

## 4.5 Well Correlation Panel

Figure 4.2 displays a well correlation panel for the E Shale and North Cape Shale, flattened on the top E Shale picks from well reports and biostratigraphic data. The transect locations were selected to show the development of the marine transgression from the northwest (more distal offshore) to the southeast (terrestrial) over the "Kahurangi Trough" (Figure 2.1), the Cretaceous depo-centre underlying the study area. Key observations are discussed in the following section. Higgs et al. (2012) outlines methods of interpreting facies types from wireline data, with some selected descriptive criteria listed in Table 8. Facies interpretations were not necessary for the North Cape and E Shale intervals as they have been previously described (see Table 9, Chapter 6).

*__Table 8__ Guideline for interpretation of wireline and palynoflora data, and the resultant paleobathymetry and wireline signatures that would be expected in ideal cases. Modified from Higgs et al. (2012).*

| **Interpreted Facies** | **Expected Lithology/Wireline signature** | **Palynoflora/fauna** | **Paleobathymetry** |
|---|---|---|---|
| Terrestrial | Highly variable - often described as "chattery" on wireline logs | Absence of marine flora and fauna | Above mean sea level |
| Marginal Marine (Coastal/Tidal, Lagoon, Beach) | Interbedded sands, silts and thin coals/carbonaceous zones. Highly variable wireline signature. | Trace dinoflagellates, sparse to abundant miospores, pollens | Mostly above sea level with some intervals having marine influence (brackish lagoons, coastal swamps, sulphur enriched coal measures) |
| Shallow Marine | Thick intervals of clean sandstone (low GR, NEU-DENS separation) near the shoreface, becoming finer grained in deeper water | Rare foraminifera, minor dinoflagellates | ~0-50m water depths, depending on relief |
| Offshore | Clay and silt dominated, NEU-DENS crossover, high GR readings | Rare foraminifera, minor dinoflagellates | ~50-150m water depths in this study |

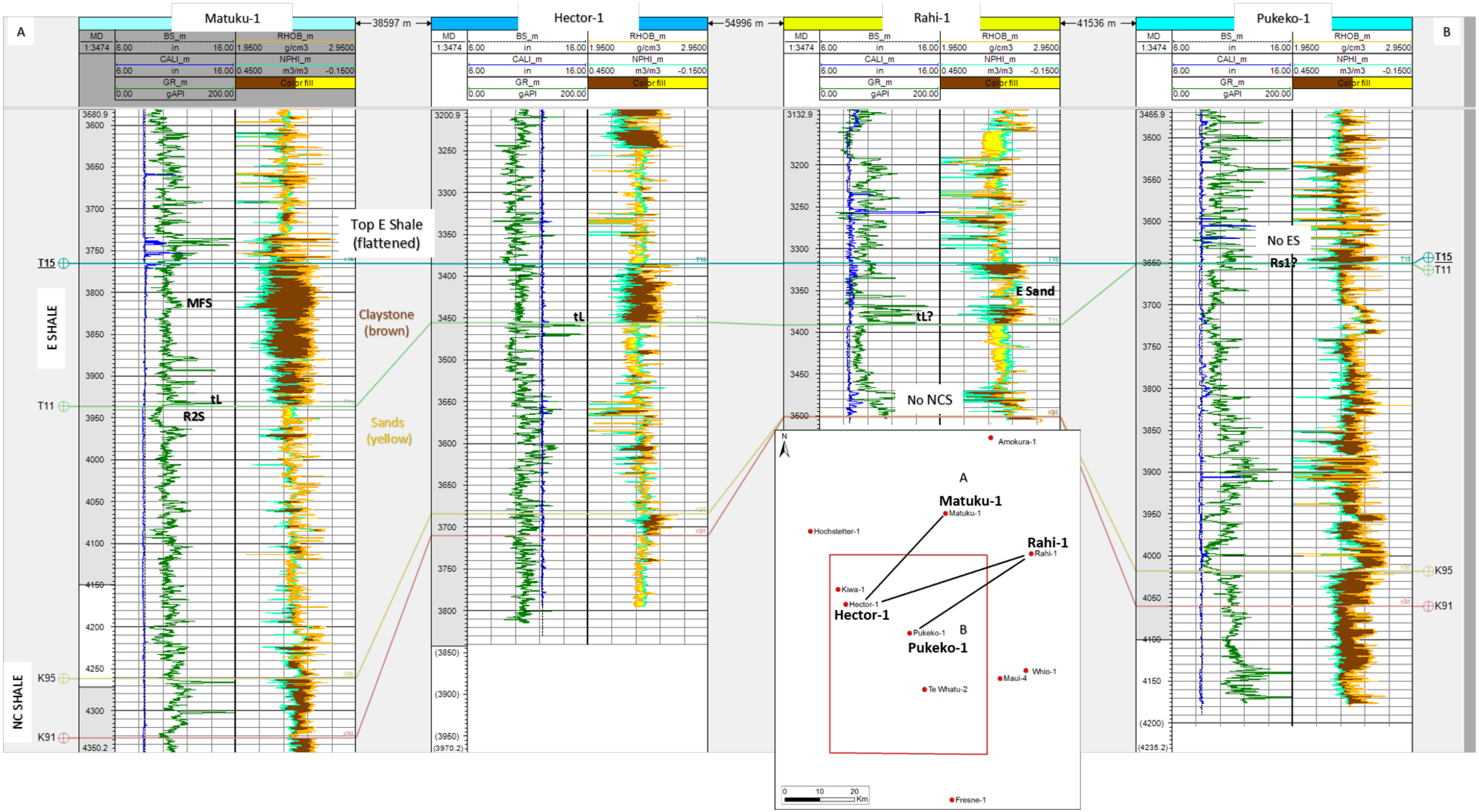



*Figure 4.2 Well correlation panel through the E Shale (T15-T11) and North Cape Shale (K95-K91) intervals at Matuku-1, Hector-1, Rahi-1 and Pukeko-1. Note thinning towards the south and east for both intervals.*

## 4.6 Volume of Clay ($V_{cl}$)

As the petrographic and MICP datasets (see Chapter 3) had limited samples to draw conclusions from, further information on the properties of the North Cape and E Shale as seals has to be inferred from log measurements. The volume of clay calculation, or $V_{cl}$, is a petrophysical method normally carried out on reservoir sections to ascertain if there is a high dispersed or authigenic clay content within them, which can introduce errors into computation of hydrocarbon saturation (Asquith, 1990). Here, $V_{cl}$ is used to infer areas of enhanced seal quality by focusing on the seal intervals only.

Two methods can be used to calculate $V_{cl}$, either by using the gamma ray log or the neutron/density logs. The gamma method was selected in this study due to acquisition in all wells, and due to the fact that the gamma log is less susceptible to erroneous readings in sections of over gauge borehole. Clay content of a formation of interest is calculated by creating a gamma ray index curve, and then converting it to $V_{cl}$ response by the following equations:

$$I_{GR} = \frac{GR - GR_{(Clean-Sandstone)}}{GR_{(Shale)} - GR_{(Clean-Sandstone)}},$$

Where,

$I_{GR}$ is gamma ray clay index

GR is log response, API units

$GR_{clean}$ is log response in clean sands adjacent to the area of interest, API units

$GR_{clay}$ is log response in claystone within the area of interest, API units

And

$V_{cl} = 0.33(2(2xI_{Gr})-1.0)$ (*in consolidated formations*)

This study calculated the $V_{cl}$ for the E Shale and North Cape Shale for the wells where it was present as a moderately thick, fine-grained marine package with the potential to act as a seal. The resulting curves are displayed on the well section panels (Appendix 4) for comparison with mercury injection capillary data points represented by Sneider seal values at the appropriate depths. Input parameters for the $V_{cl}$ calculations are contained in Appendix 5. Results are discussed in Section 4.9.

## 4.7 Neutron / Density Cross-plots

Due to the paucity of MICP data available for the North Cape and E Shales, additional methods of investigating wireline logs were trialled to identify sections with enhanced seal capacity. Lawrence and Field (2014) in their study of Taranaki seal rocks displayed neutron and density logs at the same depths and suggested that good seals could be grouped by higher density readings (above 2.55 g/cm$^3$) and low neutron porosity values (below 0.3 m$^3$/m$^3$), with poorer seals showing low densities and high neutron porosity (methodology is detailed in Appendix 6). Neutron/density plots for Matuku-1 and Kiwa-1 with the corresponding MICP Sneider seal values are shown in Figures 4.3 to 4.4 using the same parameters as Lawrence and Field (2014). In Figure 4.3, this method shows an inverse relationship in the E Shale, with better seal values sitting to the right of the graph, indicating a poor match. In the North Cape Shale (Figure 4.4), Sneider seal values improve to the left of the graph. These results are ambiguous and suggest low neutron/high density values are not definitive indications of good seal properties. Further MICP data is required to confirm this.

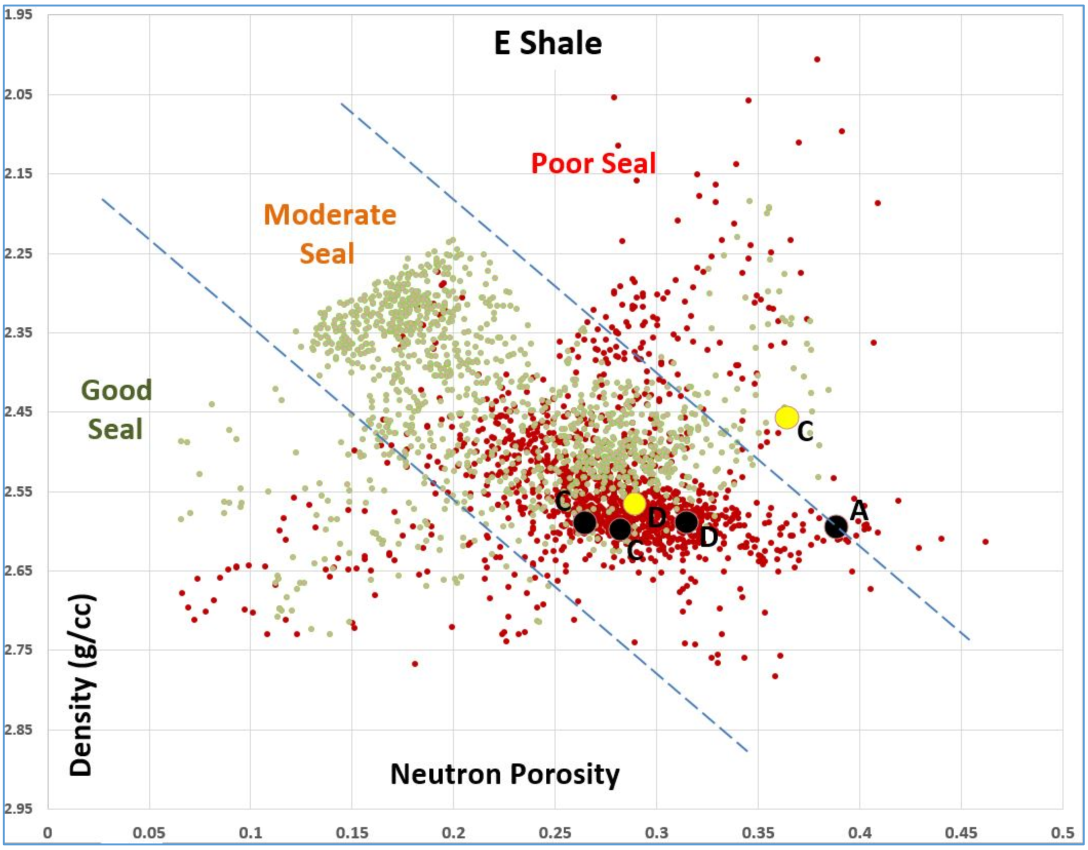



*Figure 4.3 Neutron-Density cross plot for Kiwa-1 and Matuku-1 over the E Shale. Relevant Sneider seal values shown in yellow (Kiwa-1) and black (Matuku-1) at the same depths. No obvious relationship exists between better MICP results and the "good" seal cut-off used by Lawrence & Field (2014), suggesting other factors such as rock fabric probably have greater influence than neutron porosity and density.*

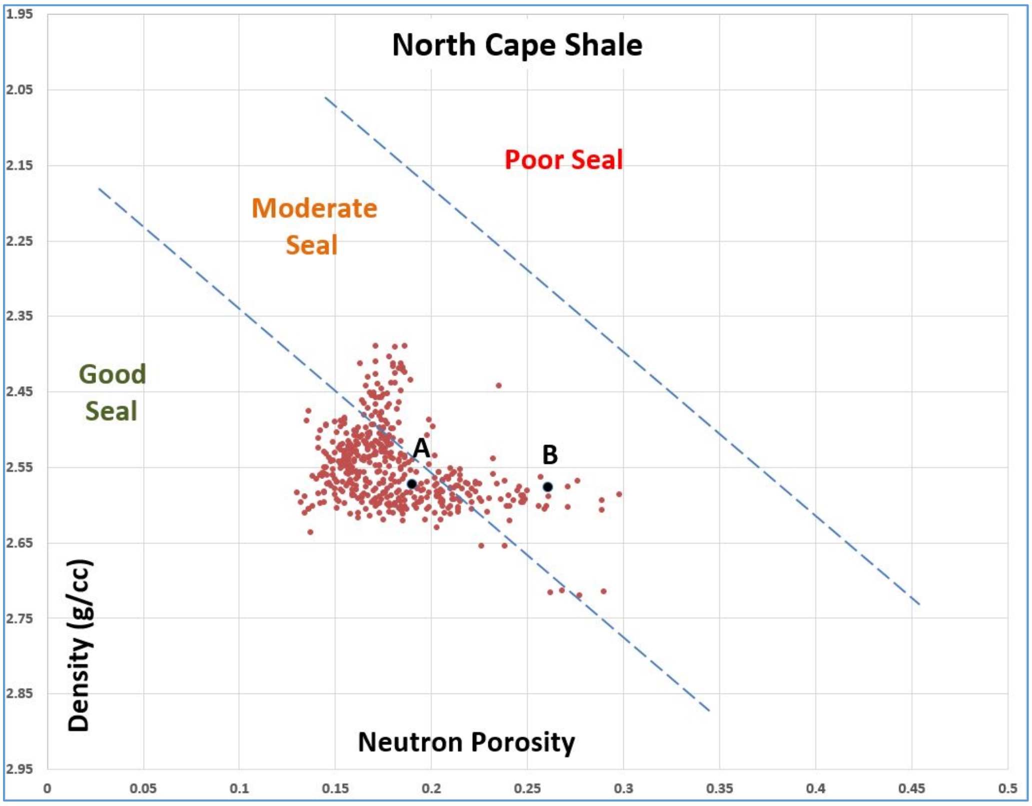



*Figure 4.4 Neutron-Density cross plot for Matuku-1 over the North Cape Shale. Sneider seal values shown in black. A better relationship is shown with better MICP values skewed the left, but with limited samples this method requires more MICP analysis for testing and validation.*

## 4.8 Discussion and Conclusions

Comparison of seal interval thicknesses between wells shows a general pattern of thinning in both the E Shale and North Cape Shale to the south and east, with increasing sand content (Rahi-1) and in some cases a change to a terrestrial environment (Pukeko-1, Whio-1).

The E Shale appears to be a thick and competent sealing interval within the Matuku-1 well, further north at Amokura-1 and in Hochstetter-1. Thinning of the E Shale unit takes place south west at the Hector-1 and Kiwa-1 locations, but is still represented by a moderately thick package albeit with some sandy/silty intervals. Transgressive lag deposits, represented by a thin glauconitic rich sandstone package from recovered core samples in Amokura-1, are interpreted at the base of the E Shale. Strata at the top of the transgressive lag also display bioturbated zones immediately underlying thick claystones within the Amokura-1 core and possibly in other wells.

Maximum flooding surfaces (MFS), indicated by high gamma zones near the centres of claystone packages, are interpreted within Amokura-1 (3570m) and Matuku-1 (3820m) wells. A MFS does not appear to be present in other offset wells. MICP tests of the Matuku flooding surface show excellent seal properties compared to other locations within the interval, which is consistent with the work carried out by Sutton et al. (2004). Similar results could be expected if MICP testing had been conducted within the equivalent section of Amokura-1. At the easternmost well - Rahi-1, the E Shale also thins but appears to split into two segments separated by a sand interval, possibly the result of an increased sediment supply or a short-term regressional event within the overall transgressive package.

Pukeko-1 appears to be missing a Waipawan section (NZOP[2], 2004) but still provides an important control point for the E Shale proximal limit, with the composite log suggesting a highly varied and in places "chattery" response in the overlying and underlying sediments, indicating continued terrestrial sedimentation. No equivalent marine section was identified for the E Shale and this is interpreted to be a coastal plain or marginal marine facies type, indicating the shoreline sits somewhere to the north west of this well. An alternative explanation could be that the well drilled into a seaward extension of the terrestrial environment, such as an island or peninsula. Regardless, Pukeko-1 appears to sit relatively near the shoreline, with a transition to a marine environment to the north-west.

In the North Cape Shale, the thinning directions are seen to be almost identical to the overlying E Shale. An important point of difference is that the transgressive sequence penetrates further south, as it is present above the Pukeko-1 basement high. The thickest and best sampled section in the Matuku-1 well has a possible maximum flooding surface at 4303m (Appendix 4). No transgressive lag deposits are interpreted at the base of any North Cape well penetrations but a gradual fining up appearance in the Matuku-1 composite log suggests that the North Cape drowning event was more gradual in this location with no erosive lower contact. Thin sections (42 to 18m) are preserved within Kiwa-1, Hector-1 and Pukeko-1, which appear to have some interbedding with fine sands and silts, suggesting a close proximity to the shoreline. No MICP data were available to quantify the sealing capacity of these interbedded sections.

Volume of clay ($V_{cl}$) comparisons between the different wells identify some interesting points. Some wells demonstrate an elevated clay content in the basal sections of the E Shale (Amokura-1, Hector-1, Matuku-1 and Rahi-1) caused by the abundance of soft deformable glauconite. While this might suggest enhanced seal potential, MICP tests from the interval in Matuku-1 show it only has fair to moderate seal integrity. High clay concentrations alone are shown to not be indicative of good seal quality but are required in conjunction with another seal enhancing factor. Maximum flooding surfaces identified in Matuku-1 display high VSH concentrations at both North Cape and E Shale level and also provide the two best Sneider seal results, supporting the findings of Sutton et al. (2004).

The neutron/density plots of recorded wireline data within Kiwa-1 and Matuku-1 demonstrate that this quick-look method of identifying seal rocks is not robust and produces results at odds with MICP data. Further testing of this method would require a greater number of MICP data, preferably from cored sections from a range of settings and a number of wells. In order to fully extrapolate the findings outlined in this chapter away from well locations a detailed review of seismic reflection data is required, with a focus on locating marine facies boundaries.

# 5. Seismic Reflection Interpretation

## 5.1 Introduction

Interpretation of seismic reflection data is one of the primary tools used for understanding and predicting stratigraphy within sedimentary basins and is a key method of hydrocarbon exploration and development. Numerous 2D and 3D seismic reflection surveys acquired in offshore Taranaki were used in this study to inform and conduct horizon mapping of the North Cape and E Shales. Horizons were extrapolated from wells that penetrated one or both of the candidate seal intervals (well tops), allowing mapping onto the equivalent seismic reflectors. Seismic appearance of the facies intervals is discussed in this chapter and used to make inferences about seal presence and depositional facies during the Latest Cretaceous (North Cape) and early Eocene (E Shale) seal units.

Previous seismic interpretations carried out over the study area (e.g. Matthews et al., 2005; Shadlow et al., 2008; Thrasher and Powis, 2012; Viskovic and Reynolds, 2015; Bull et al., 2016) have concentrated on shallower levels above the seals as part of regional mapping or prospect level work, with most of their focus on reservoir intervals instead of seals. Interpretation in this study aims to continue and build on this previous work using additional geological and geophysical data that has been made available since these reports were published. Interpretation in this chapter focuses mainly on the seal units.

## 5.2 Geological to Seismic Modelling

The purpose of seismic interpretation is to represent geology by its seismic expression. Therefore, it is useful to briefly revisit the physical characteristics of the rocks these reflectors represent and the nature of the formations above and below the two seal units. Figure 5.1 shows an idealised section which serves as an approximate analogy for the possible seal sequences as they sit within a shallow marine transgressive environment - and where the interpreted horizon picks sit relative to these boundaries.

## 5.3 Data Utilised

Seismic reflection data in both 2D and 3D format were obtained from public databases administered by New Zealand Petroleum and Minerals at the Ministry of Business, Innovation and Employment

(MBIE) and loaded into Petrel 2015.5® interpretation software. A listing of the surveys is available in Appendix 7 and their distribution is illustrated in Figure 5.2.

Well data, including North Cape and E Shale tops identified in Chapter 4, were retained and time/depth relationships from wells that acquired checkshot surveys were extracted from well completion reports and loaded to establish seismic-to-well ties. Seismic data was checked for consistency between surveys, with seismic start times set to zero unless processing reports stated a required correction. Polarity of all seismic data used for interpretation was checked for consistency and confirmed as SEG positive, where an increase in acoustic impedance (hard reflector) is displayed in this study as a red peak (Figure 5.3).

## 5.4 Seismic to Well Ties

Seismic to well ties, or time to depth relationships, are required to translate formation tops from wells, measured in depth, onto the equivalent reflections from seismic data which are recorded in two-way travel time. The relationship to convert time to depth requires velocity information - as distance (depth) = velocity*time. Velocity of seismic soundwaves varies in the subsurface depending on the rock types and burial history of the stratigraphic succession through which the soundwaves travel. Once this relationship is known (or can be estimated), information can be extrapolated from the wells into areas with seismic coverage.

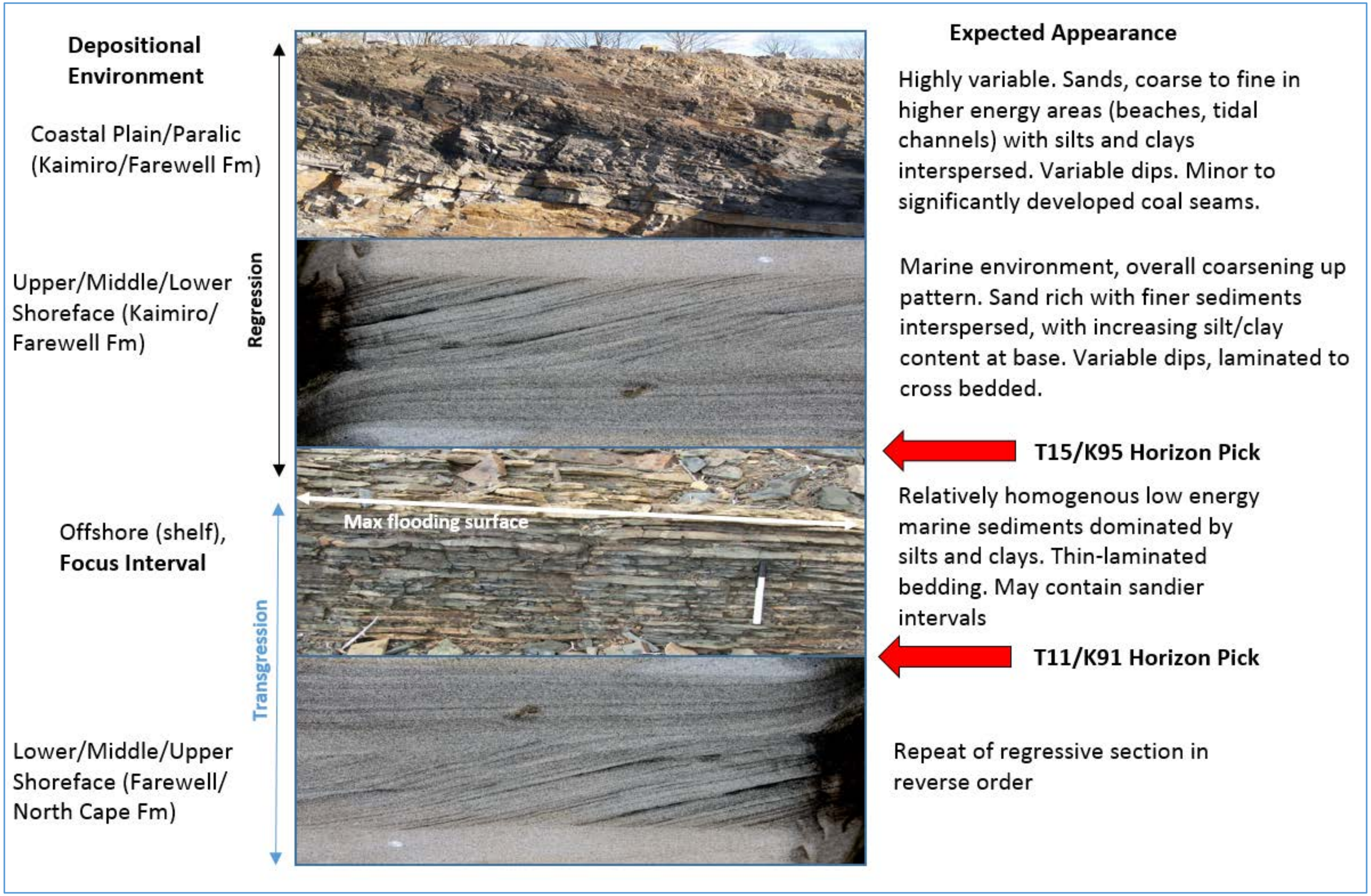



*Figure 5.1 Idealised section of sedimentary sequence above and below the seal intervals of interest.*

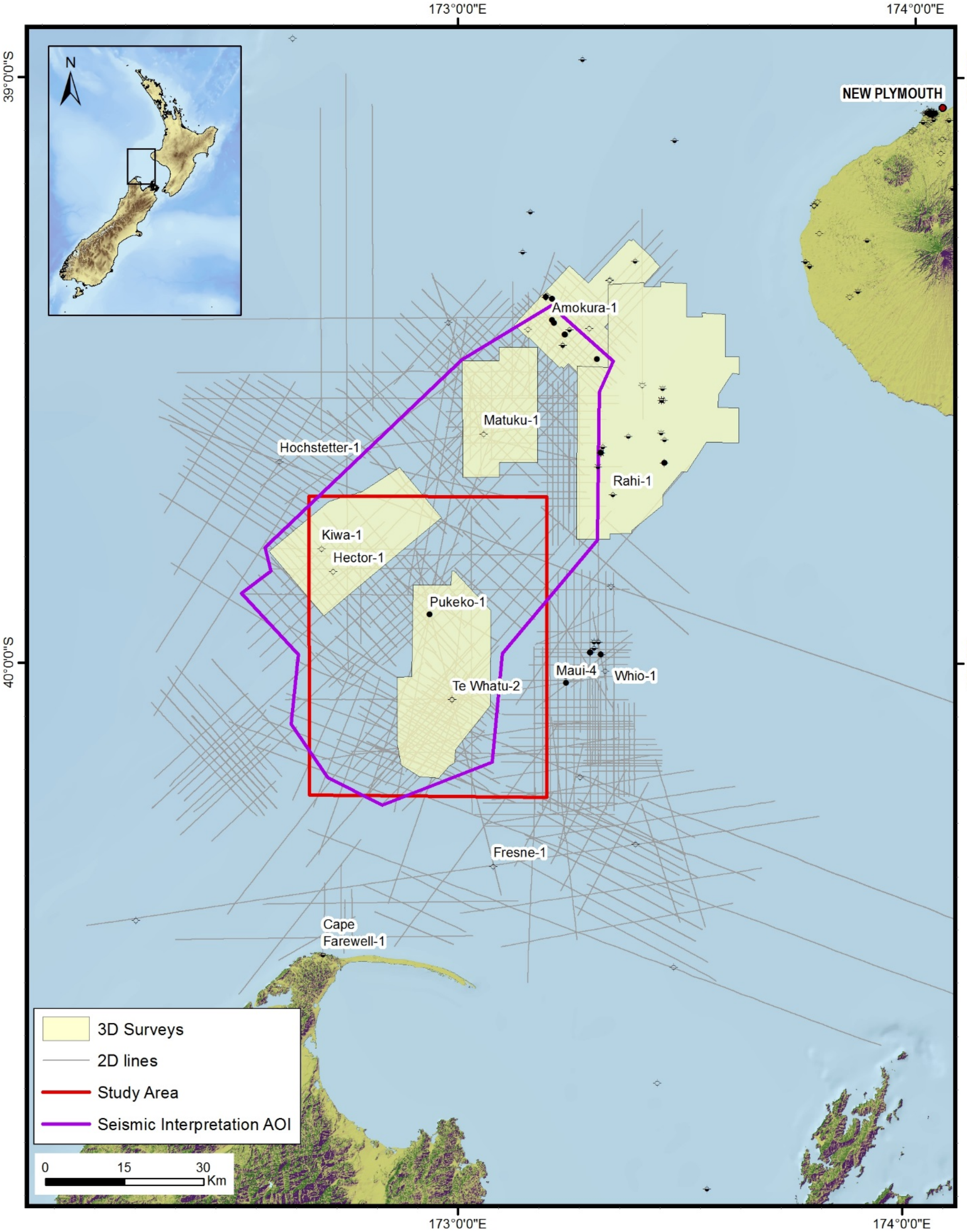



*Figure 5.2 Seismic and well basemap. Purple polygon indicates area where interpretation effort was concentrated due to seismic data coverage and quality restrictions. Information on the seismic reflection surveys is given in Appendix 7.*

Checkshot surveys are routinely acquired post-drilling to provide the velocity information required to correlate well and seismic reflection data. Checkshot recording is carried out by gradually lowering a receiver into the open well while emitting a sound wave at the surface and measuring travel time between the source and receiver (Figure 5.4). In the absence of a checkshot survey, less precise time-to-depth information from sonic and density logs can be substituted. However, these logs are more limited as errors can be introduced where the walls of the wellbore cave-in and become over gauge ("bad hole" effect) which invalidates the log readings over the section. Sonic and density logs are also not routinely recorded in the near surface of offshore Taranaki wells; many wells lack good log velocity data shallower than 1500 meters.

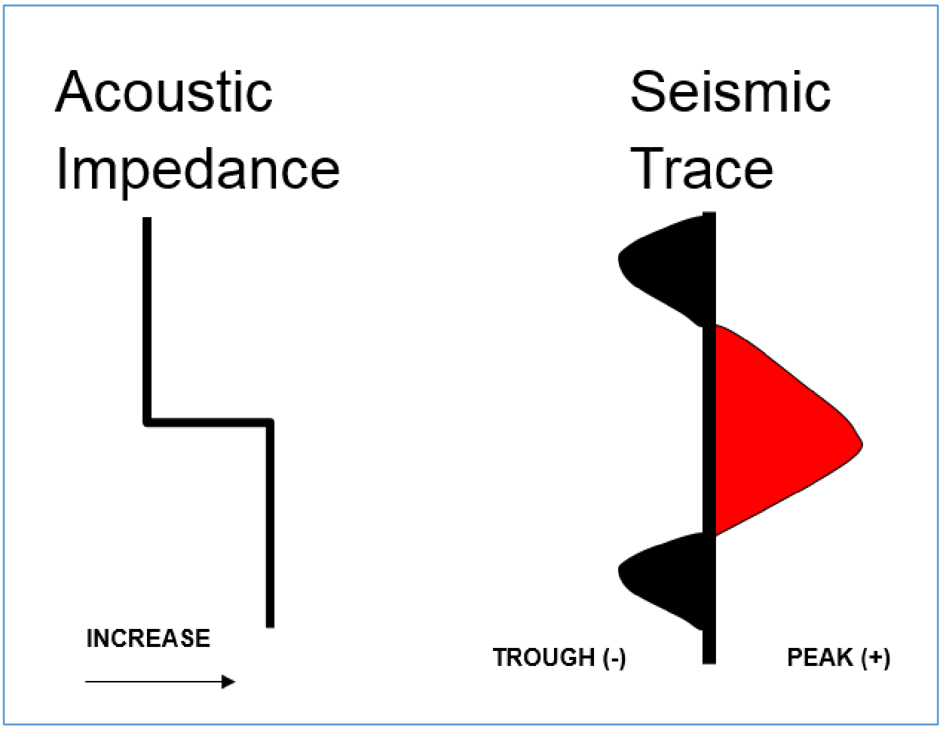



*Figure 5.3 An increase in acoustic impendance (red peak) defines a hard event.*

This study constructed ties using the best available information to create a time to depth relationship for eight wells using the Petrel® seismic to well tie module. Strong and easily correlatable reflectors above and below the interval of interest (T40 and Basement) were used to establish the reference points required for a reliable match. Perfect matches between wells and seismic, while desirable, are often not able to be achieved. Poor quality or limited data coverage, sub-seismic changes in geology (thin cemented or washed out zones) or inexperience with creating seismic well ties results in offsets between the tie and seismic reflectors. An example of the synthetic tie for Amokura-1 is shown in Figure 5.5 which displays an acceptable but not perfect match. A compromise between an excellent tie and a useful match for regional mapping was reached. No attempt was made to match seismic character in the seafloor to Miocene section due to this being out of scope.

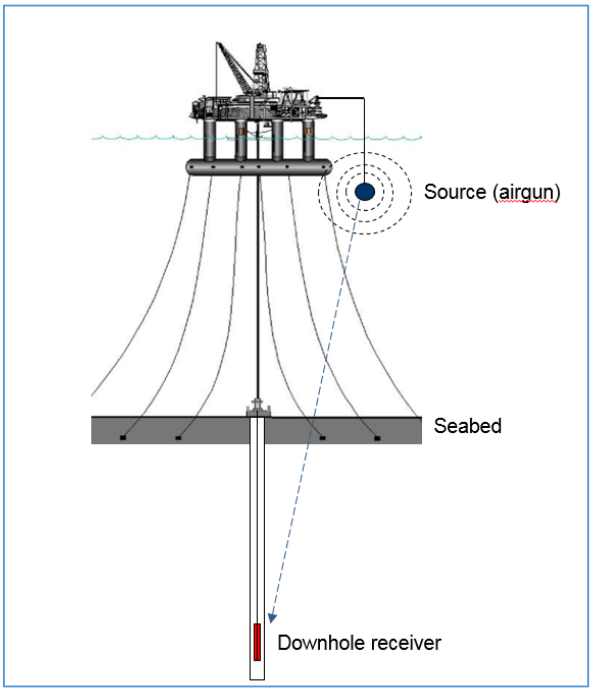



*Figure 5.4 Checkshot survey acquisition offshore. The seismic source is placed in the water next to the rig and emits a signal which is picked up by the receiver downhole.*

## 5.5 Seismic Interpretation Workflow

The following methodology describes the preparatory and quality checking steps taken to ensure the interpretation process was robust:

1. Time to depth relationships were created for the wells using a combination of checkshots, sonic data and density data to construct a synthetic well tie with the nearest intersecting 2D or 3D survey. If no checkshot survey was acquired, sonic and density logs were used stand-alone to generate the synthetic tie.

2. Checks for seismic consistency were undertaken by interpreting a shallow seismic horizon that was consistently mappable on composite lines between each survey to verify if there were any unexplained offsets between them (misties). Continuity without offsets of this shallow strongly reflective horizon between surveys gave more confidence when subsequently picking deeper and less coherent reflectors. Where misties were identified, this horizon was used as a guide point for

vertically shifting the offset data up or down. Shifts applied are available in Appendix 7 next to the relevant survey.

3. Seismic horizons were interpreted over 3D surveys initially. These were then used to inform picking of the interlinking 2D surveys. Significant faults which offset one or both the potential seal intervals were identified and mapped, with fault polygons generated for use in surface generation.

4. Top E Shale and Top North Cape Shale surface maps were generated to check for interpretation errors and to show the extents of prominent features that could act as possible depositional controls such as significant faulting, basement highs and areas of non-deposition/erosion.

5. Amplitude extractions were performed over the Pipeline and Hector 3D surveys in an attempt to identify sedimentary features such as paleoshorelines for paleogeographic maps in Chapter 6.

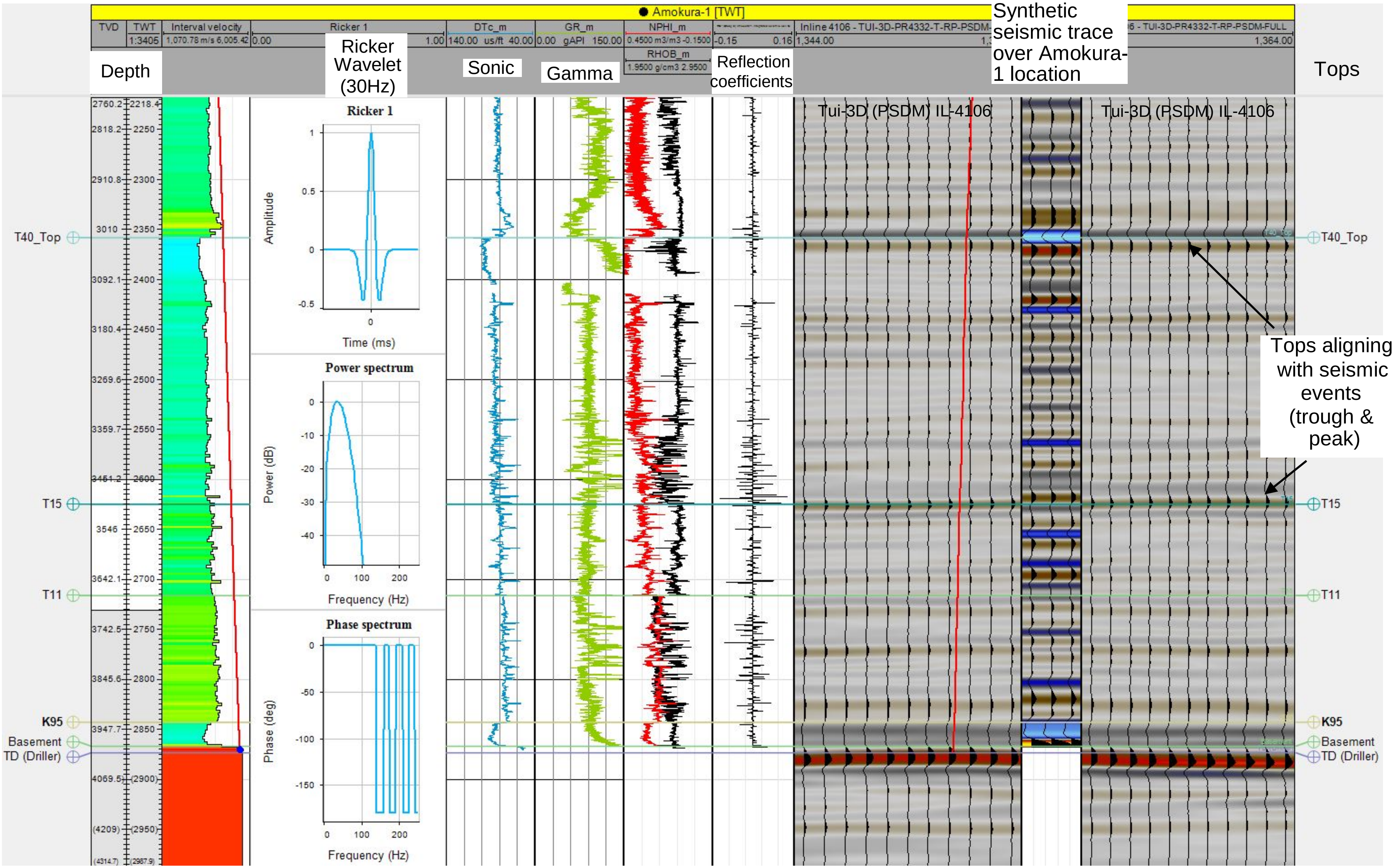



*Figure 5.5 Amokura-1 seismic to well tie. Note slight discrepancies between the generated synthetic trace and the recorded seismic data (basement top not aligned with seismic peak). This synthetic was deemed close enough to the seismic for mapping purposes. Significant offsets require editing of noisy data points or stretching/squeezing to align with the seismic data.*

## 5.6 Interpreted Horizons

Six horizons were mapped initially over the study area (Figure 5.6). Interpretation began at the Tui and Matuku 3D surveys where excellent data quality, multiple well penetrations and seismically resolvable thickness of the seal units (100m+) resulted in confident interpretation. The interpretation was then extended south into the more difficult areas where thinning, facies changes and reductions in seismic quality made the interpretation less confident. Figure 5.7 provides an overview map showing the maximum extent of interpretation carried out and annotation of the prominent features with key features noted in Table 9. Names of prominent geological features previously identified by Thrasher et al. (2012) were retained for this study.

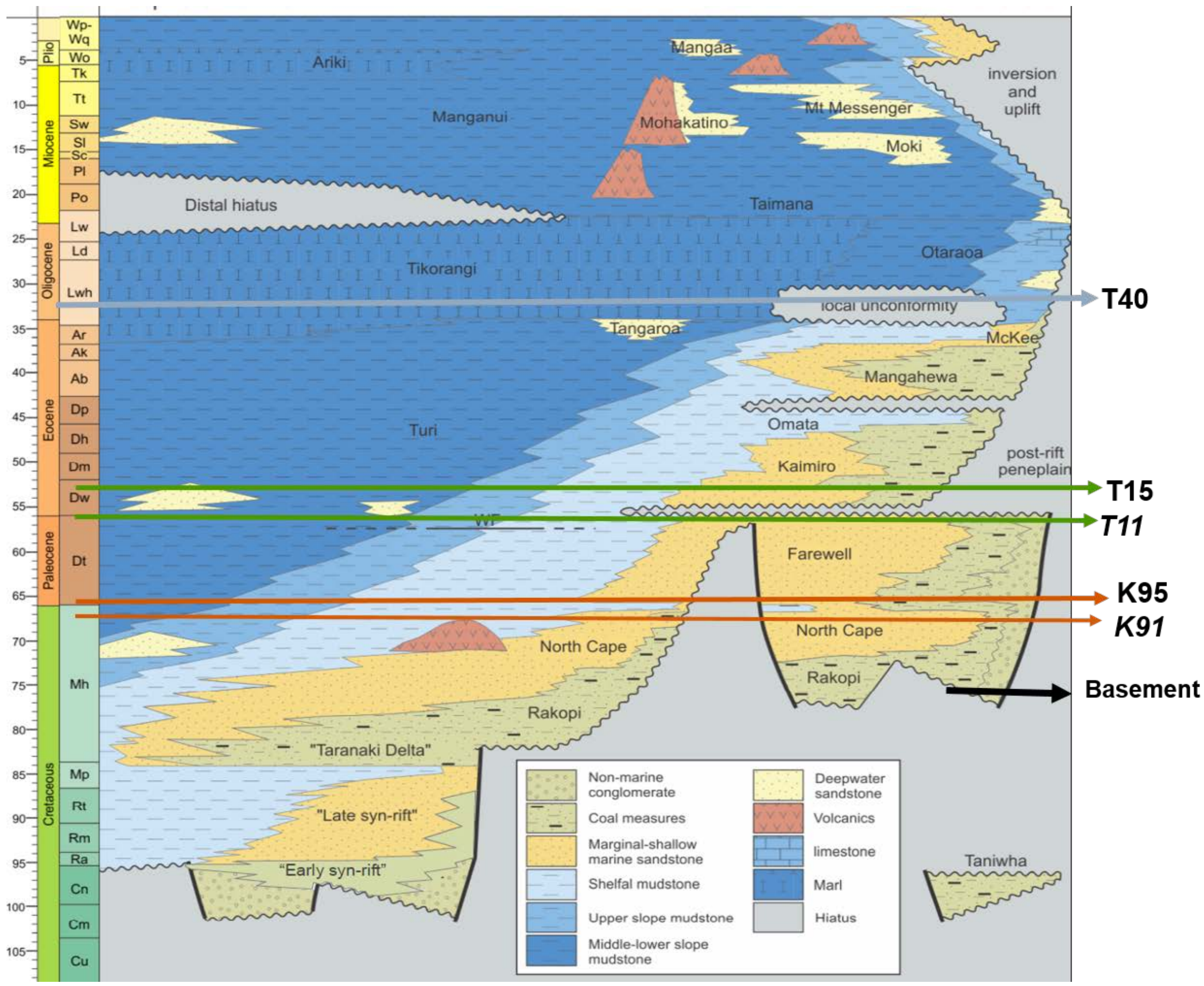



*Figure 5.6 Seismic event locations and ages. Modified from Raine et al., 2012*

### 5.6.1 T40 (base Oligocene)

The T40 horizon is widely present throughout the basin as a seismic trough (soft event) generated by the velocity contrast between the top Turi Formation (slightly over-pressured, claystone dominated lithology) and the underlying Kapuni Group (usually normally pressured, sandstone dominated) (Webster et al., 2011). The primary purpose for including this horizon was to help quality-check seismic surveys and to identify offsets between them (misties). Interpretation was completed over the seismic interpretation AOI (Figure 5.2) to provide a seismic reference point and flattening surface with no further analysis carried out.

***Table 9*** *Seismic expressions of the picked events*

| Horizon | NZ Stage | Age (Ma) | Formation Name | Peak/ Trough | Comments |
|---|---|---|---|---|---|
| **T40** | Whaingaroan (Lwh) | c.33 | Turi (top) | Trough | *Widely present strong reflector over basin, weakening south of the Te Whatu Inversion. Used for synthetic generation, quality checking and mistie adjustment.* |
| **T15** | Waipawan (Dw) | 54 | E Shale (top) | Peak | *Moderate peak in northern sectors at Tui Platform, becoming weaker in the central area south of Kahurangi Trough, discontinuous over wide areas in the southern region south of Pukeko High.* |
| **T11** | Waipawan (Dw) | 56 | E Shale (base) | Trough | *Weak trough in the northern areas (Maui High - Tui Platform), dimming further in the central area at the Hector Platform and unable to be mapped in the southern areas south of Pukeko High* |
| **K95** | Upper Haumurian (Mh) | 66 | North Cape Shale (top) | Trough | *Moderate trough in the northern area becoming weaker south of the Pukeko High and Hector Platform. Autotracks well despite being relatively thin.* |
| **K91** | Upper Haumurian (Mh) | 67 | North Cape Shale (base) | Peak | *Weak peak at the central area (Kahurangi Trough), weakening further as it travels south. Unable to be mapped south of Pukeko High/Hector Platform.* |
| **Basement** | Cretaceous (various ages) | c.100 | Basement (top) | Peak | *Strong peak over areas of up-thrown basement, becoming weak and poorly resolved where thick coal measures overlie it within grabens/half grabens.* |

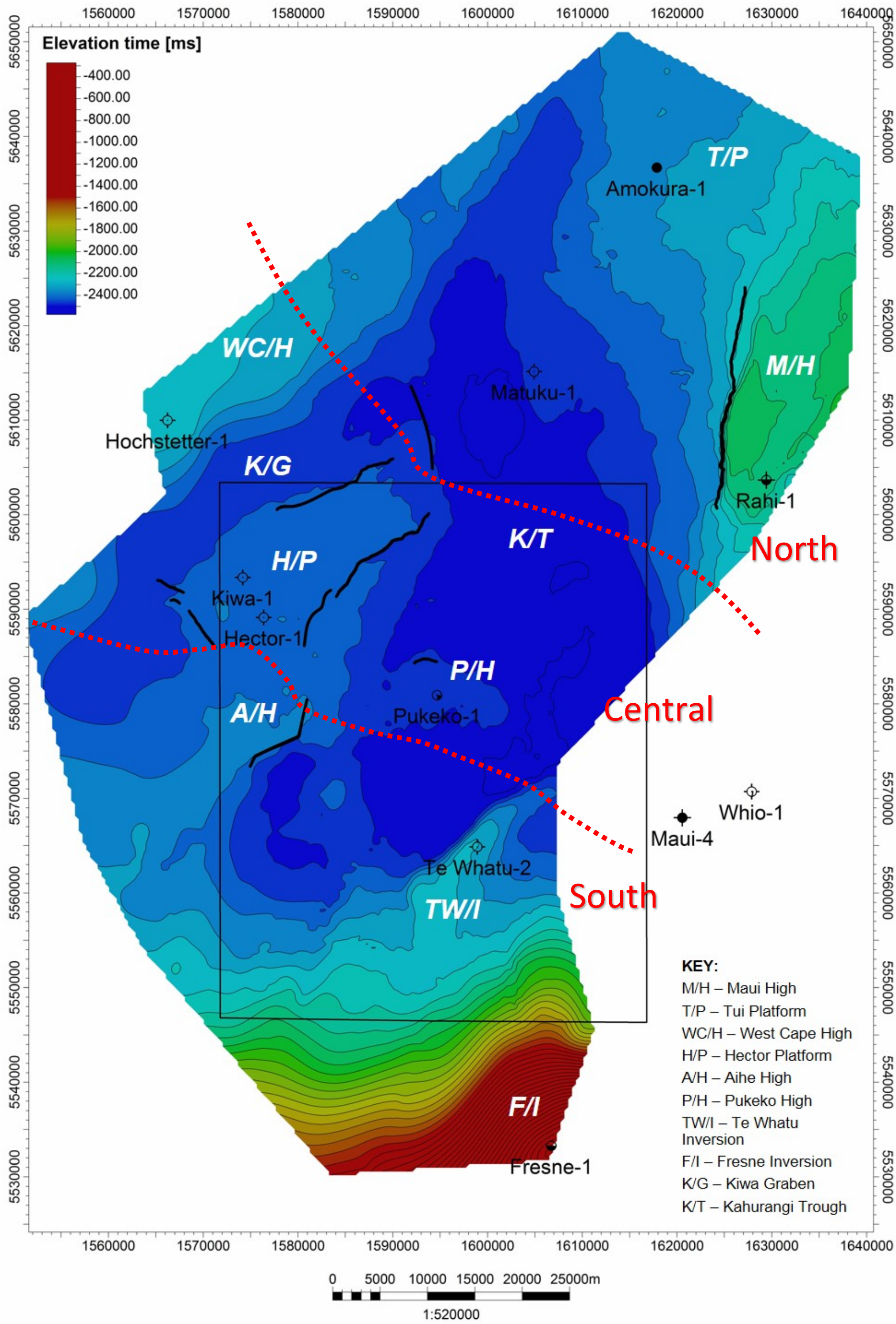



*Figure 5.7 Basemap showing elevation contours for the T40 horizon. See key on map for elevation of surface in two-way time. Subdivisions of North-Central-South are referred to in sections 5.7.1 and 5.8.1 to differentiate areas for detailed discussion.*

### *5.6.2 T15 top E Shale equivalent (early Eocene, Waipawan Stage)*

T15 is represented by a moderate seismic peak within the Tui and Matuku 3D surveys. This trend continues south over the entire study area with the event becoming weaker and less distinctive a short distance north of Pukeko-1. Here, it merges with a bright package which correlates with the coal measure sequence encountered at c.3600m in this well.

### *5.6.3 T11 top Farewell Formation (Paleocene, Teurian Stage)*

A moderate to weak trough represents the T11 over the Tui area which becomes weaker on the southern margin of the Kahurangi Trough and almost indistinguishable from T15 over the Hector Platform and Pukeko High. Limited interpretation was carried out due to thinning of the E Shale sequence and deteriorating seismic quality.

### *5.6.4 K95 top North Cape Shale (Latest Cretaceous, Latest Haumurian Stage)*

K95 is marked by a moderate trough in the Kahurangi Trough area and a stronger trough over the Tui Platform where it sits directly over basement. As it continues to the south into the study area, it weakens due to either increased depth or a gradual facies change. Over the Hector Platform it can be mapped with relative ease compared to the overlying T15 reflector.

### *5.6.5 K91 near top North Cape Formation (Late Cretaceous, Latest Haumurian Stage)*

K91 represents the base of the North Cape Shale. It displays as a weak seismic peak in the Kahurangi Trough within the Matuku-1 well and weakens further to the south over the study area making horizon picks difficult. Limited interpretation was carried out as it became apparent, as with the T11 horizon, that the appropriate reflector could not be confidently identified over most of the area.

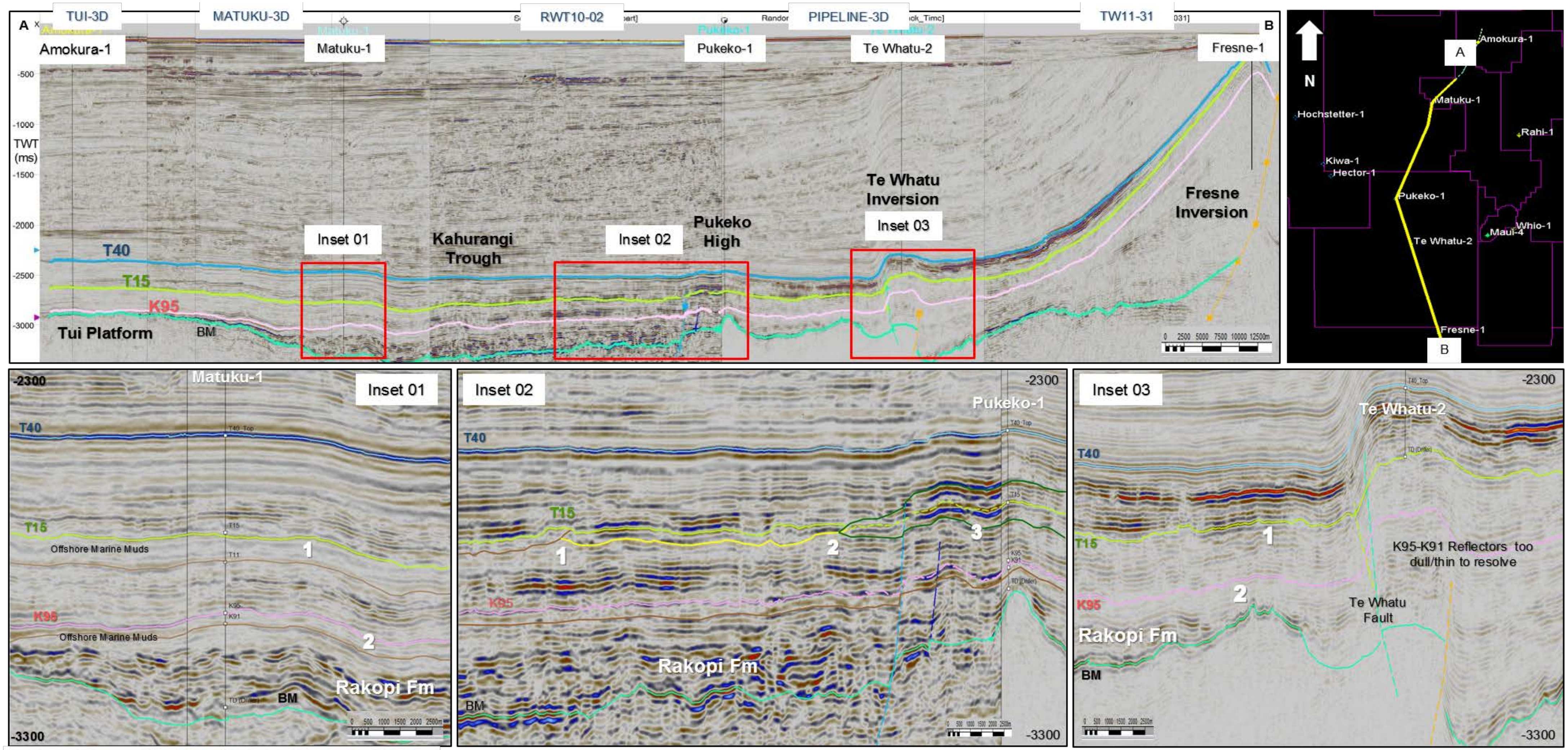
### *5.6.6 Basement*

Basement mostly consists of weathered to fresh granite in all wells except Rahi-1 where it was described as schist and is represented as a hard event (strong peak) at the bottom of coherent seismic reflections in both 2D and 3D surveys. Where the Rakopi Formation (Figure 5.6) is absent, Top Basement is easily interpreted and can be mapped confidently. Within areas of thicker pre-Paleocene sediments, top basement is ambiguous and unable to be easily separated from overlying bright discontinuous reflectors interpreted as Rakopi Formation coal measures. As high confidence regional mapping of basement was not a focus of this work, the horizon was only mapped where needed to convey fault offsets.

## 5.7 E Shale Interpretation (T15 – T11)

In general, the top E Shale (T15) was more confidently mapped in the areas north of the Hector Platform and Pukeko High (see Figure 5-8 for locations) as this comprised non-deformed or weakly deformed strata, continuous reflectors not offset by significant faulting and good seismic quality. 2D survey lines in this area were also relatively easy to interpret with confidence at this level. The simplest explanation for this is that the reflector sits within a marine to deep marine sequence. Further south the sequence becomes harder to interpret with blocky and bright discontinuous reflectors, most likely indicating a diachronous sedimentary package and lateral change in depositional environment. Coupled with an interpreted thinning of the marine package, the line defining the facies change appears to trend in a broadly east-west direction.

Viewed in a north-south seismic composite line (Figure 5.8) the T15-T11 interval is typically seismically bland within the Kahurangi Trough (a surface map of the T15 is shown in Enclosure 1). Low reflectivity and parallel continuous reflectors make up the majority of the package, with an often poorly defined base marking the top of the underlying sand-prone Farewell Formation. Further south, the interval thins with bland reflectivity replaced by discontinuous bright reflections appearing approximately 15 km N-NE of the Pukeko-1 well. Onlapping beds at the position where the reflectors change character from bland and flat lying to moderately reflective and wavy indicate the position of a shoreline or shoreline-related feature from the marine trangression and are identified in sections of the 2D surveys RWT10 and MOHUA14. Stratigraphically, this shoreline could represent the distal limit of the coal measure sequence seen in the Pukeko-1 well in the E Shale equivalent interval. Continuing south towards the Fresne Inversion reveals no discernible further change from blocky, chaotic reflectors - indicating that the coastal plain/fluvial environment continues in this direction.




North of study area. Intervals below T15 and K95 horizons (1 and 2) seismically bland with parallel continuous reflections. Interpreted as offshore marine silts/clays which is supported by Matuku-1 and Amokura-1.

Centre of study area. T15 horizon easily carried from Matuku-1 but becomes difficult to define closer to Pukeko-1. Edge of brown line (1) defines edge of the T15-T11 seismically bland package and possible facies change. Brightening to south (right) , a marine/terrestrial transition (yellow) is picked (2) before changing to coal measures at (3).

South of study area. Brighter packages below T15 likely coal measures with blocky discontinuous reflections (1). K95-K91 interval (2) is seismically dim with no discernable K91 horizon able to be interpreted. Possibly too thin to seismically resolve.

*Figure 5.8 Seismic composite transect from north to south*

### 5.7.1 *Discussion by Sub Regions*

In order to simplify discussion, the seismic interpretation AOI was sub-divided into a north, central and southern area. Boundaries for these areas are indicated in Figure 5.7. The northern sector covers Amokura-1, Matuku-1 and Rahi-1. T15-T11 horizons between Amokura-1 and Matuku-1 are confidently picked and seismic appearance indicates a continuation of marine strata based on the continuous and relatively conformable nature of the reflectors. Thinning without entirely pinching out is observed at the eastern margin onto the Maui High, with the T15-T11 covering most of this elevated feature as it can be tracked as far east as Rahi-1.

Over the central area containing Kiwa-1, Hector-1 and Pukeko-1, the distance between the T15 and T11 horizons reduces, indicating thinning to the south and east. Base E Shale (T11) becomes discontinuous and difficult to pick, preventing effective isochore map generation. An absence of Waipawan-aged strata at Pukeko-1 indicates T15-T11 sediments were either not deposited or were deposited and eroded by subsequent regressional events. Down flank of the Pukeko High to the north, a possible transition between marine/shallow marine environments can be interpreted by a change in seismic facies (Figure 5.8, inset 02). T15-T11 is present as a thin unit at Kiwa-1 and Hector-1, indicating this platform was affected by the marine transgression at these locations, but it may revert to a terrestrial environment a short distance (5 km) to the south of the central area. The crest of the Aihe High shows a rapid thinning of both the T15-T11 and K95-K91 reflectors, suggesting this high was long-lived and prominent throughout both the marine transgressions.

The southern area, including Te Whatu-2, appears to reside in the transition zone between marine and marginal marine/terrestrial. Reflectors are discontinuous, bright and difficult to map continuously, giving this sector a lower level of confidence of the seismic picks. The interpreted T15-T11 horizons attempted to map a Waipawan aged interval, this but could reside a short distance above or below the picked horizons. Efforts to refine it would ultimately require better quality seismic data or a well penetration to validate the interpretation.

## 5.8 North Cape Shale Interpretation (K95 – K91)

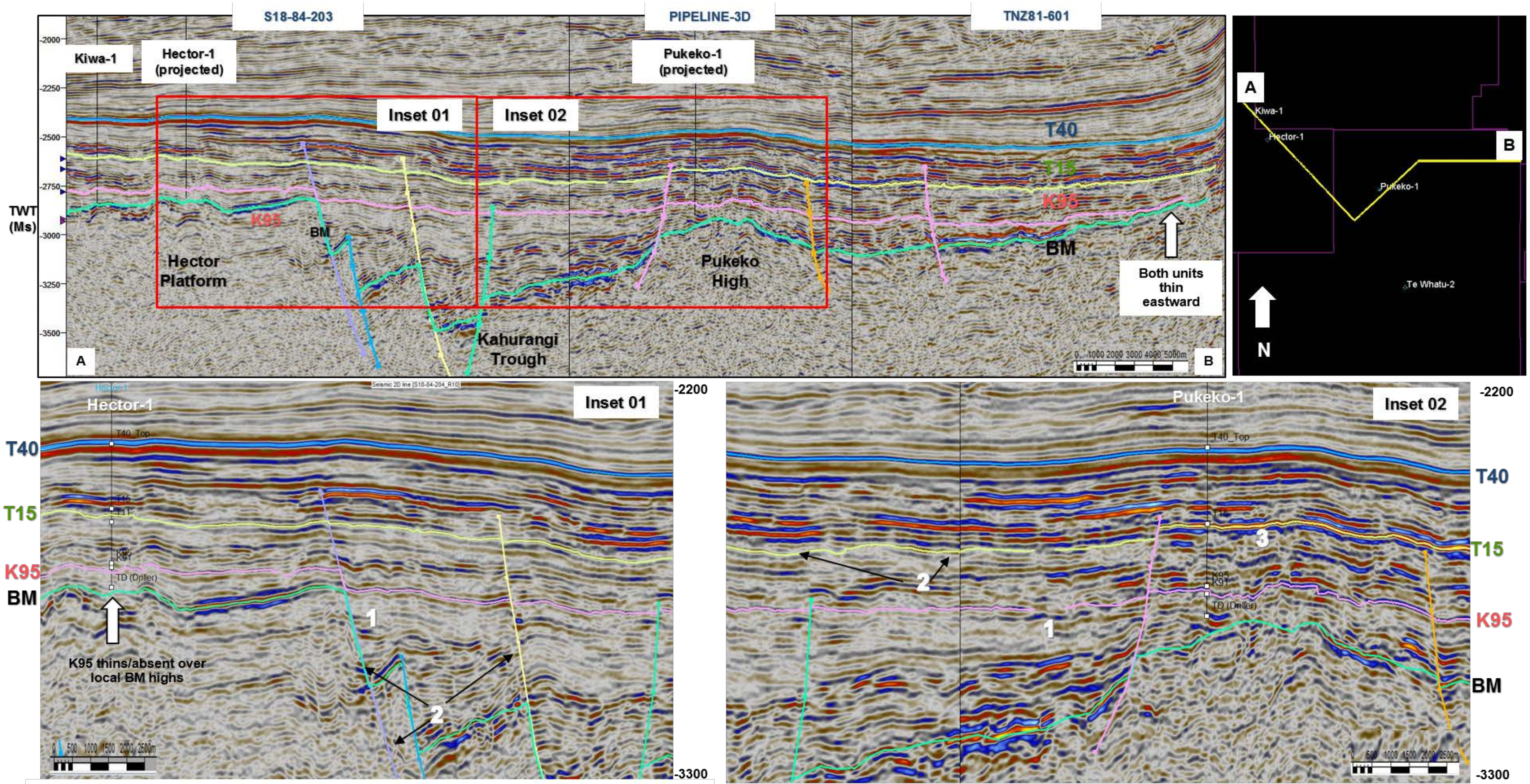
A surface map of the K95 is shown in Enclosure 2. Despite being a thinner, more deeply buried package than the overlying T15-T11 interval, the K95 horizon can be mapped further south more confidently than the T15-T11 - suggesting a marine transgression with greater extent. Seismically, it is represented as a dim interval overlying brighter blocky reflectors of the Rakopi Formation in the Matuku 3D survey, and becomes variably brighter to the south. Resolution is poor on both 2D and 3D survey datasets south of the Te Whatu Inversion but the K95 horizon can be confidently picked in large areas of the Hector Platform and Kahurangi Trough (Figure 5.9). The interval thins rapidly to the east before reaching the edge of the Maui High. It cannot be traced beyond the easternmost lines of the TOKE07 survey or the Tui Platform east of Amokura-1 where it sits one seismic reflector above Basement (Figure 5.10). Due to the thinness and present-day depth of the unit (4 km+ in almost all locations), a basal pick is not confidently identifiable over much of the study area. By the Fresne-1 location, equivalent aged sediments are a coastal plain/fluvial coarse-grained facies, suggesting that the gradual change in reflection characteristics to the south represents a shallowing of the marine environment to the point it becomes a nearshore sand-dominated unit.

### *5.8.1 Discussion by Sub-Regions*

The Maui High has had a greater effect on constraining the eastern limit of the K95-K91 interval than the later T15-T11 flooding event, as the K95-K91 interval appears to thin and pinch out in a relatively straight line from north to south at or near the Amokura-1 location before reaching the base of the high. A thick preserved section of North Cape Shale at the Matuku-1 location shows that the transition westwards back to marine facies was reasonably abrupt (< 25 km), indicating low relief at the shelf edge.

In the central area, all three well penetrations encountered the K95-K91 as a marine claystone, with thinning to the south and east observed. Its presence as a 40m thick unit in Pukeko-1 on top of a basement high suggests that the flooding event responsible for North Cape Shale was more expansive than the E Shale event. This is possibly because North Cape Shale deposition was influenced by a larger change in base level (than that for the E Shale) in order to cover these exposed highs or a differential rate of subsidence in this sector of the basin (Beggs, 2010) .

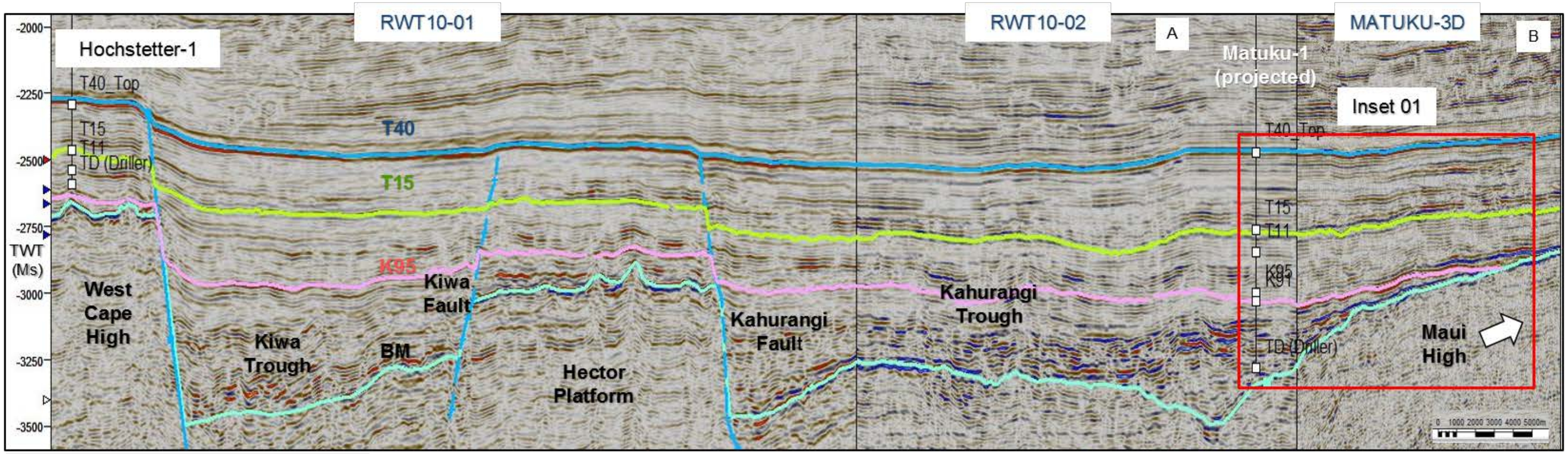
In the southern area, the North Cape Shale most likely formed a SW-NE trending shoreline either at or just south of the Te Whatu Inversion. This shoreline formed when deposition was controlled by a graben and a normal fault downthrown to the south east. While K95-K91 marine facies cannot be confidently mapped below the Te Whatu-2 well location, it is possibly preserved since this location was a fault-bound depression at the K95-K91 time.

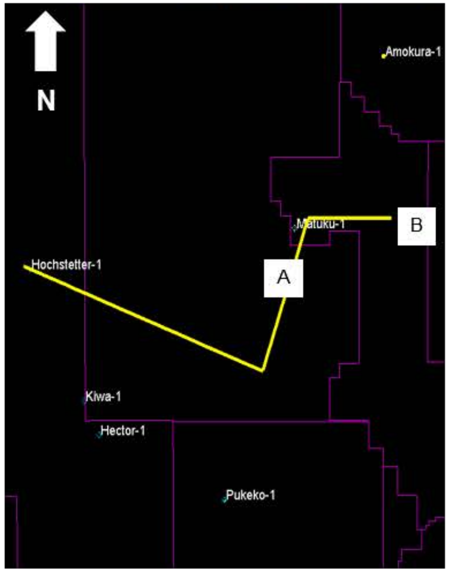


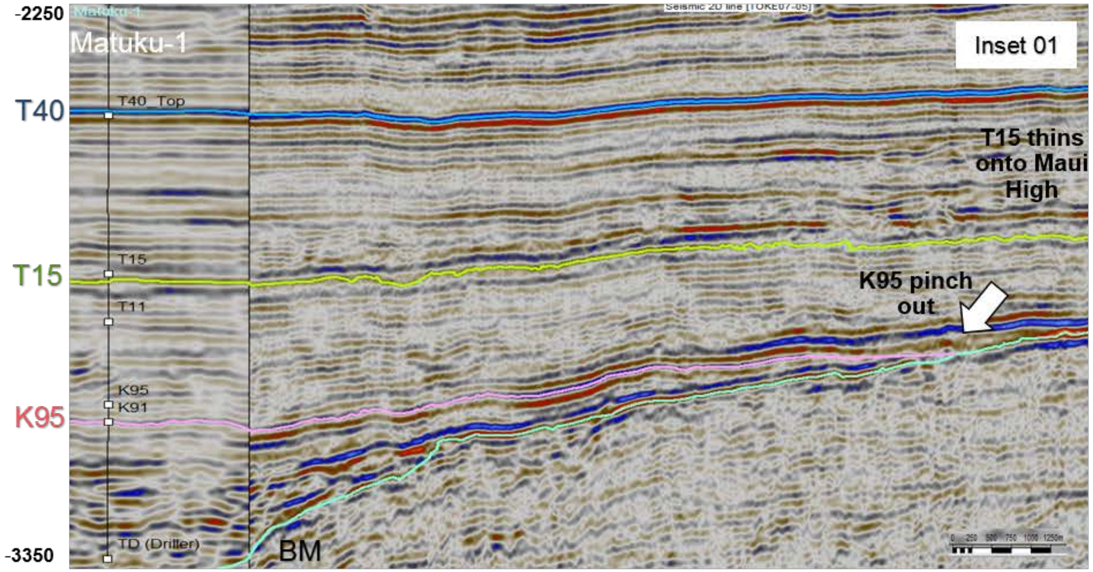

West of study area. Distance between T15-T11 and K95-K91 well tops has reduced to a single reflector. Note (1) thickening of K95 on downthrown side of the Kahurangi Fault System (2). Faults appear to have ceased major movement by T15 horizon.

Centre/East of study area. Note (1), brightening of K95-K91 section onto Pukeko High, (2) discontinuous T15 horizon with indentations which could represent channels, followed by bright discontinuous block reflectors above the Pukeko High (3).

*Figure 5.9 Seismic composite transect from west to east through the study area.*




Area to north-east of study area. T15-T11 section thins updip to east onto the Maui High. K95-K91 section pinches out at the foot of the high. Pinch-out occurs in north and south directions. No Late Cretaceous sediments preserved at Rahi-1 or in any publically available records of the Maui Field wells, indicating the Maui structure was in place and influencing sedimentation in the Late Cretaceous. Subsidence or erosion in the Paleocene as T15-T11 section transgresses it.

*Figure 5.10 Seismic composite transect from west to east to the north of the study area.*

## 5.9 Amplitude and Variance Seismic Extractions

Seismic attribute extractions from 3D seismic volumes can be useful when making inferences about facies types and identifying linear features such as fault offsets more readily than by viewing seismic amplitudes alone. RMS (root mean square) amplitude is useful for picking depositional sedimentary features with abrupt boundaries, such as channels and coal measure sequences, while variance calculates the difference between one seismic trace and the adjacent trace and assigns a value to it, which makes it suited to mapping vertical displacements.

After interpretation of the T15 and K95 horizons, geophysical extractions were taken from the Hector and Pipeline 3Ds to study the variability of the seal intervals and identify any sedimentary features indicative of facies (channels, barrier islands, river deltas etc.) (Figure 5.11). Extractions were selected by taking smoothed T15 and K95 surfaces (tops of the conceptual seal intervals) and selecting windows of varying thickness between 10 milliseconds (ms) to 50 ms below them to study how variable the seismic signals were within the T15-11 and K95-K91 packages. Seismic attributes included RMS amplitude and variance.

Variance proved particularly useful for picking significant fault displacements such as the normal faults bordering horst/graben features at the Hector Platform and the Te Whatu Inversion. RMS Amplitude maps were however less definitive, with no clear interpretable demarcation of a shoreline able to be identified at either level.

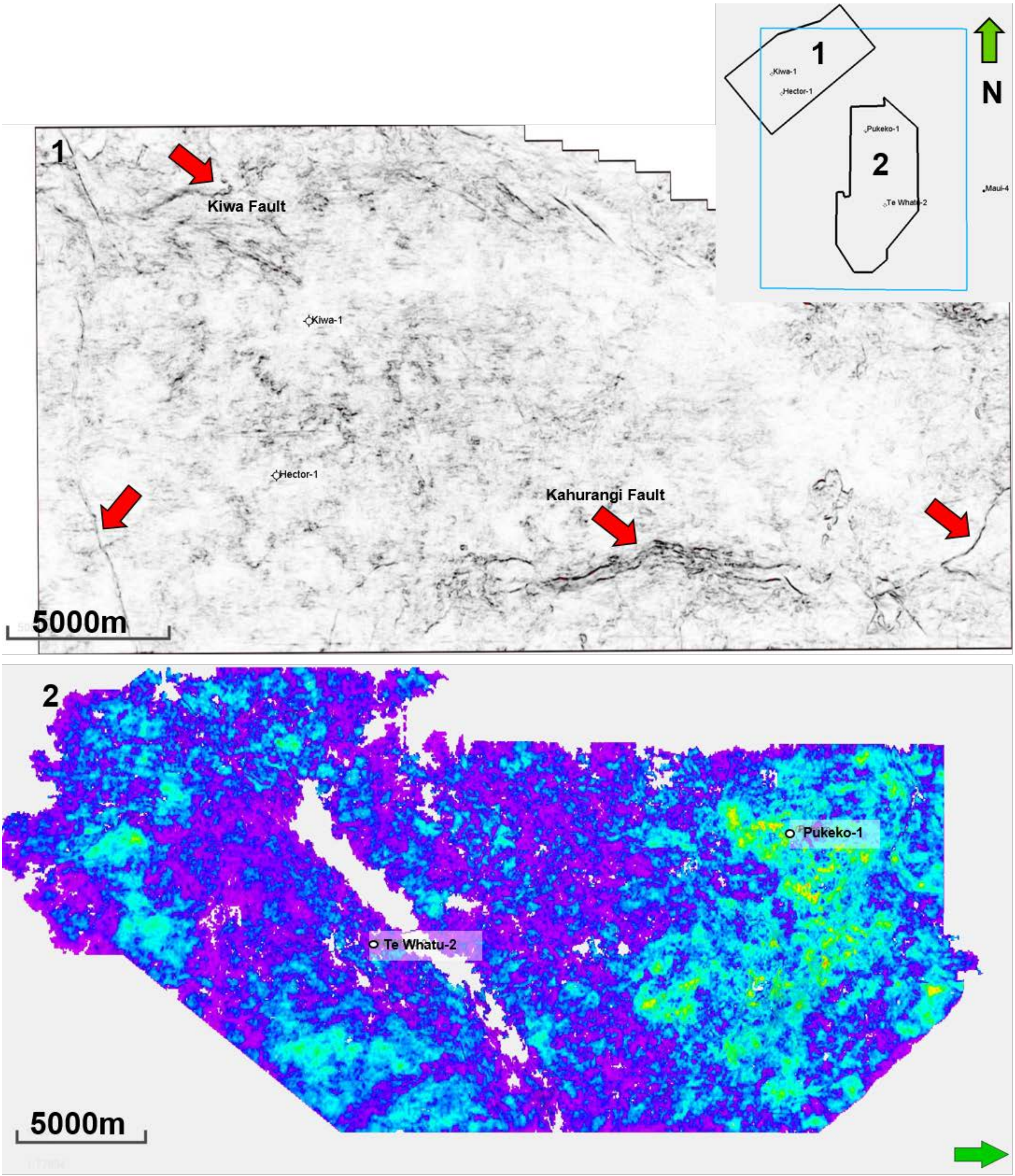



*Figure 5.11 Variance extraction (1) and RMS amplitude extraction from the Hector and Pipeline 3D surveys. Panel 1 was taken from the T15 horizon (approx. top E Shale) at -2644 ms clearly displaying major faults (red arrows) which displace this horizon (Kahurangi and Kiwa Faults). Panel 2 taken from the top of the K95 horizon to 20 ms below and shows some variation around the Pukeko-1 location but is insufficient identify the shoreline at this level or at the shallower T15 interval.*

## 5.10 Faulting

Small-scale normal faults (< 10 ms of throw) are present throughout the area but large-scale features with offsets extending from Basement to the T40 horizon are concentrated at the edges of the Kahurangi Trough bounding the Hector Platform, the Aihe High and the West Cape High. While the K95-K91 interval thickens into the Kahurangi Trough in some locations, the overlying E Shale does not and has minimal fault offset compared to the K95-K91 interval. Most movement as part of the basin forming rifts had likely ceased by Late Paleocene, with resulting offset in the shallower T15-T11 probably being the result of differential compaction. A Late Paleocene (~56 Ma) cessation of rifting is consistent with previous estimates of the timing of rifting (e.g., Reilly et al. 2015) and is also approximately coincident with the end of Tasman Sea opening (Veevers and Li, 1991). Reverse faulting is observed only in the southern edge of the study area at the Te Whatu Inversion and outside the study area at the Fresne Inversions and at the Maui High. Shortening and uplift on these structures is dated to the Miocene or later (King and Thrasher, 1996; Reilly et al., 2015), therefore they were not examined in detail due to their movements postdating the deposition of potential seal rock intervals studied.

# 6. Paleogeography

## 6.1 Introduction

From the previous analysis covering basin history, seal rocks, wells and seismic interpretation (Chapters 2 to 5), paleogeographic maps were constructed of the marine transgressions which led to the deposition of the E Shale, North Cape Shale and their proximal equivalents. The maps are intended as a complementary addition to the regional paleogeography work published by Strogen (2011) and Arnot and Bland et al. (2016). This study focuses on the marine facies as these are believed to represent the most likely seal(s) of Paleocene and Late Cretaceous reservoirs respectively, within the study area. This chapter discusses map inputs, presents the maps and analyses the distribution of likely seal rocks with the aim of better understanding the role seals play in the petroleum system of the southern Taranaki Basin.

## 6.2 Inputs from Previous Chapters

Two paleogeographic maps have been created to show the extent of maximum flooding surfaces in the Waipawan (c. 55 Ma) and latest Cretaceous (c. 66 Ma). Interpretation was taken from work in Chapter 4 on wireline log character with additional input from paleoenvironment analysis of cutting and core samples. Seismic interpretation provided the basis for extending the facies belts away from well penetrations with changes in seismic reflector style, continuity and character used to inform the drawing of boundaries. Modern analogue depositional environments were compared to the paleogeographic maps to ensure appropriate scaling.

## 6.3 Paleoenvironments from Biostratigraphy

Table 10 collates previous interpretations that were made from biostratigraphic analysis of cuttings and core samples taken from the studied wells. The samples were examined on the basis of whether the flora and fauna were deposited in offshore marine, nearshore marine or terrestrial environments. The results were cross-checked with the interpretations made in Chapters 4 and 5 and used as map inputs. The description of paleoenvironments overlaps with facies types as they both describe the geographical environment of deposition.

## 6.4 Modern Analogues for Interpretation of Paleoenvironments

Since the best seal rocks occur in low energy marine environments as described in Chapter 3, the most important facies boundary to identify is the top shoreline that separates wholly marine from marginal-marine facies. Where inadequate seismic data was available or where post-depositional erosion has occurred, the transition zone between marine and terrestrial environments was often unable to be identified in seismic lines. Best estimates were made using analogues.

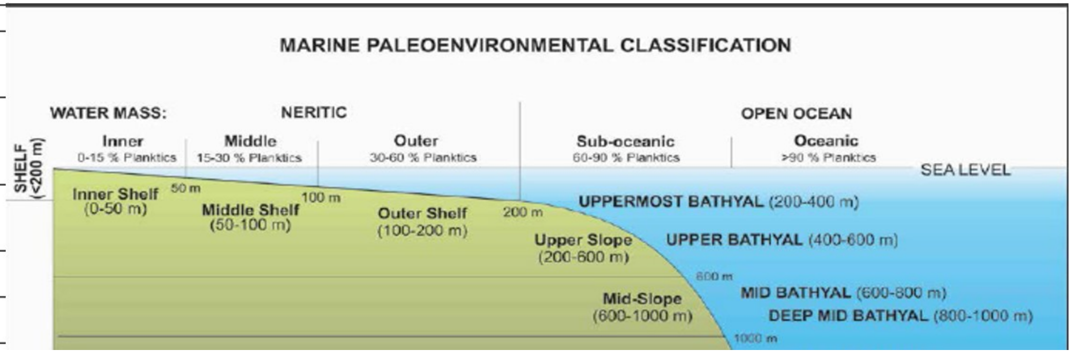
In order to correctly scale the widths of the shoreface/beach/coastal plain transition zones and also to check the more confidently identified areas, satellite images of coastal sections were selected for comparison from what could be considered analogous environments. The current New Zealand coastline with its incised geometry resulting from rising sea levels is taken as an example, with possible comparable sections from Nelson, Golden Bay and the southern West Coast of the South Island examined (Figure 6.1). These three areas were selected to cover all scenarios of low, moderate and high relief coastlines, respectively. These were then compared to the interpreted facies belts when creating the maps to ensure realistic widths were applied. In general, shoreline (beach) sections should be no more than 1.5 km in total width, with the transition zone to coastal plain taking place rapidly where elevated topography was present near to the shoreline. Gently sloping hinterland sections behind the shoreface would be expected to generate a wide marginal marine/tidally influenced zone or barrier islands before transitioning into coastal plain sections. Inset A (Figure 6.1) at Nelson/Mapua is considered to be a possible analogy for the Late Cretaceous and Waipawan transgressional events.

*Table 10 Available paleoenvironment data for the 12 studied wells. Marine paleoenvironment classification tables from Todd Exploration Ltd. (2014)*

| **E SHALE** | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Well** | **AGE** | **Top (m)** | **Base (m)** | **Paleoenvironment** | **Overlying section** | **Underlying section** | **Source of data** |
| **Amokura-1** | Dt - e Dw | 3497 | 3674 | Marine | ? | Shelf-Upper shoreface | PR2920 |
| **Matuku-1** | e Dw | 3728.5 | 3936 | Inshore marine | Lower coastal plain | Inner marine-lower coastal plain | CR2014-148 from Matuku-1 WCR. |
| **Hector-1** | Dw | 3385 | 3455.4 | Inshore marine-non-marine (?) | Lower coastal plain | Non marine(?) - coastal complex | PR5072 |
| **Hochstetter-1** | e Dw | 3076 | 3202 | Inshore marine | Lower coastal plain | Upper coastal plain | PR5072 |
| **Kiwa-1** | e Dw | 3358.5 | 3425 | Coastal complex - parlic | Paralic | Coastal complex | PR5072 |
| **Rahi-1** | NA | 3317 | 3391 | NA | NA | NA | None acquired |
| **Pukeko-1** | l Dw-l Dh | 3555 | 3658 | Upper to Lower Coastal Plain | Lower coastal plain | Coastal plain | PR5072 |
| **Maui-4** | Dt-Dw | 2266 | 2664 | Non-marine | Non-marine | Non-marine | PR4512 |
| **Fresne-1** | NA | | | | | | Section missing in well |
| **Whio-1** | e Dw | 2606 | 2627.5 | Coastal complex | Upper coastal plain | Coastal complex | CR2015-09 from Whio-1 WCR |
| **Cape Farewell** | NA | | | | | Non-marine | PR 1234. Spudded in Farewell Formation. |
| **Te Whatu-2** | NA | | | Not penetrated | Not penetrated | Not penetrated | PR5072 |
| | | | | | | | |
| **NC SHALE** | | | | | | | |
| **Well Name** | **AGE** | **Top (m)** | **Base (m)** | **Paleoenvironment** | **Overlying section** | **Underlying section** | **Source of pick** |
| **Amokura-1** | l Mh | 3935 | 3977 | Marine (shelf, close to land) | Shallow marine (my interp) | NA | PR2920 |
| **Matuku-1** | l Mh | 4261.5 | 4332.5 | Inner marine-lower coastal plain | Upper coastal plain | Inner marine-lower coastal plain | CR2014-148 from Matuku-1 WCR. |
| **Hector-1** | e Dt | 3684 | 3709.9 | Offshore marine | Offshore marine grading inshore | Inshore marine | PR5072 |
| **Hochstetter-1** | NA | | | | | | Not reached at well location |
| **Kiwa-1** | l Mh-e Dt | 3680 | 3698 | Paralic to netritic | Neritic(?) | Paralic to netritic | PR5072 |
| **Rahi-1** | NA | | | | | | Not present at well location |
| **Pukeko-1** | l Mh-e Dt | 4018 | 4060 | Inshore marine | Lower coastal plain | Inshore marine | PR5072 |
| **Maui-4** | Mh-Dt | 2820 | 2840 | NA | NA | NA | PR4512 |
| **Fresne-1** | NA | | | | | | Not present at well location |
| **Whio-1** | NA | | | | | | Not reached at well location |
| **Cape Farewell** | Mh-Dt | | | Terrestrial | Terrestrial | Terrestrial | PR1234. No modern biostrat |
| **Te Whatu-2** | NA | | | | | | Not reached at well location |

Table 2 Paleoenvironmental classification (palynology biofacies)

| Paleoenvironment | Palynological recognition |
|---|---|
| *upper coastal plain* | Fluvial, swamp, and freshwater lacustrine environments. Purely terrestrial palynoflora, lack of marine organisms (such as dinoflagellate cysts). Very little or no Nypa mangrove pollen. |
| *lower coastal plain* | Includes "estuarine" = brackish water channels. Terrestrial palynoflora includes common Nypa mangrove pollen within the climatic range of this taxon – Early to Middle Eocene. Dinoflagellate cysts may be present but rare (< 1%). |
| *coastal complex* | Includes beach/bar/shoreface. Terrestrial palynoflora enriched in spores (as a result of reworking in high-energy environments). Common Nypa mangrove pollen. Dinoflagellate cysts present, up to a few percent. |
| *inshore marine* | Very shallow, nearshore marine environment. Palynofloras with moderate levels of dinoflagellate cysts (~ 5–50%). |
| *offshore marine* | Shallow to deepwater, offshore marine environment. Palynofloras contain abundant dinoflagellate cysts (~ >50%). |




Inset A
Nelson/Mapua.
Coastal plain with
barrier island
Low Relief
Hinterland.
Tidal/wave
dominated

Inset B Farewell Spit
Moderate Relief
Hinterland
High level of tidal
influence

Inset C Haast
High Relief
Hinterland
Wave
dominated

*Figure 6.1 Modern examples of a transgressive shoreline. Example A shows a low relief shoreface, example B a moderate relief shoreface with large tidal influence and example C a high relief shoreface. Widths of the coastal plain/paralic environment to approximate upper shoreface are noted for the paleogeographic maps.*

## 6.5 Results and Discussion

The general pattern of both E Shale and North Cape Shale marine transgressions is similar with distal directions to the west and north and proximal to the south and east. Emphasis was placed on locating the shoreline as the distal locations carry a higher probability of marine conditions and deposition of seal rocks while proximal conditions behind or close to the paleo-shoreline will produce thin, poor quality or absent seal rocks.

### *6.5.1 E Shale Maximum Flooding Surface, Waipawan, 55 Ma*

During the Waipawan flooding event, water depths over the southern Taranaki Basin where marine rocks are preserved were never deeper than inner shelf depths (c. 0-150m). A shallow seaway extended over the Hector Platform, with relatively deeper water extending to the west. The shoreline strikes in a broadly W-SW to E-NE direction, influenced to a small degree by the extensional normal faulting that was previously active in the basin. Elevated structures were present in the south at Aihe - possibly as a headland or peninsula extending towards the Hector Platform. The Maui High appears to have been at least partially flooded, with isolated, small higher-relief areas partially emergent or influenced by the wave base. A shallow seaway extended further to the east in the depression between the Maui High and the proto Maari structure near Maui-4/Whio-1 but its mapped eastern extent is beyond the scope of this study. Sediment supply appears to be predominantly from the coastal plain to the south and south east, building out as a regressional wedge towards depo-centres in the north and north-west. Topographic lows, such the Kahurangi Trough axis, may have been preferential paths for river systems to feed from the south around the Fresne-1 location.

Paleoenviromental data show Amokura-1 and Matuku-1 are located in the more distal parts of the system, with Amokura-1 being the most distal of all wells reviewed. Well logs support this conclusion, showing a relative thickening of E Shale strata in this direction. At the north-eastern border of the study area, the E Shale is noted to penetrate a considerable distance over the Maui High, as seen at Rahi-1. The absence of biostratigraphic or paleoenvironmental data for Rahi-1 makes it difficult to confirm but interpretation of a nearshore facies and a further shallowing of water depths south of this location fits the results of other wells examined (e.g. Maui-4, Whio-1). A definitive eastern boundary of the E Shale has not been identified as it resides outside the study area.

Near the Pukeko High, the E Shale equivalent section is largely missing. The basement structure underling this location is elevated, resulting in less accommodation space and negative differential compaction. The Pukeko High may also have acted as a barrier against marine incursions further south. There is scope for limited distribution of marine strata in tidally influenced zones on the western flank of the Pukeko High within the Kahurangi Trough axis (Figure 5.9), however south of this boundary there is a significantly reduced chance of laterally continuous marine shales being preserved.

West of the Pukeko High a potentially conflicting interpretation of paleoenvironments occurs at Kiwa-1 and Hector-1 where a paralic environment sits adjacent to an inshore marine facies. Based on seismic reflections at this level, the Hector-1 paleoenviroment interpretation is considered to be the most representative of the area as a whole. Composite logs over the section (Figure 4.2, Hector-1 & Kiwa-1 logs, Appendix 4) show this location to have some potential for preserving seal rocks, supported by three MICP tests (C-D ranges). Other elevated areas, such as the Aihe High and some small high relief features located over the Hector Platform, were identified as having very thin or possibly absent E Shale aged sediment cover. Fresne-1, beyond the extreme southern portion of the study area, appears to be missing Waipawan aged sediments. From the offset wells and the terrestrial nature of the section above and below it, there appears to be a low likelihood that the 'E Shale' marine transgression reached as far south as Fresne-1.

Difficulty in defining the southern boundary of the E Shale shoreface band was a significant problem during the course of this work, the reasons for which are not fully understood. Without well penetrations between Matuku-1 and Pukeko-1, seismic reflection data is the most appropriate tool to perform this task, but it is not effective due to either insufficient seismic resolution or inadequate coverage. An extremely low relief coastline creating a broad paralic/tidally influenced zone could have resulted in a non-distinct shoreline boundary. Further work is necessary to identify the shoreline over the wider area, which is beyond the scope of this thesis.

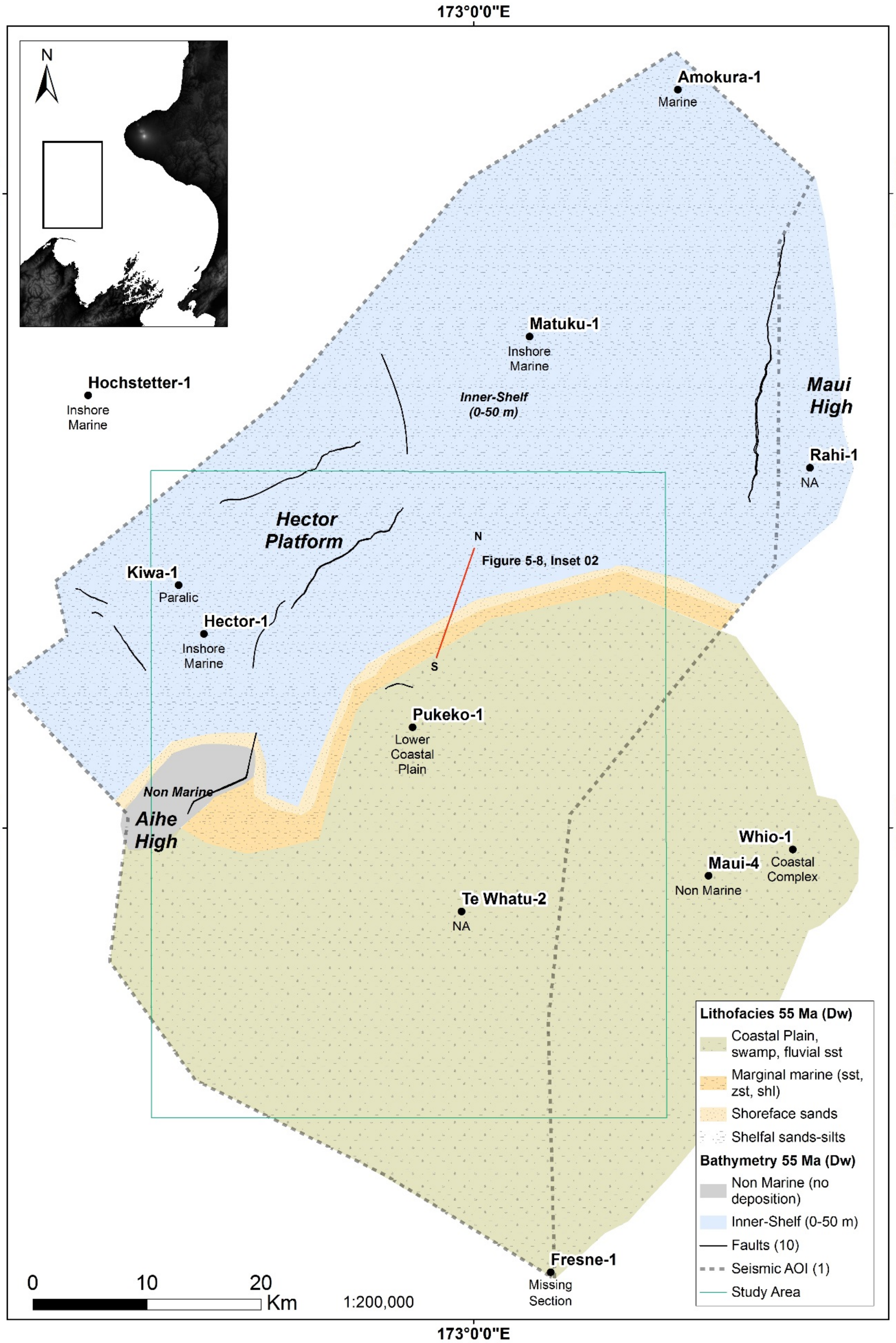



*Figure 6.2 E Shale Paleogeographic Map at Waipawan (55 Ma)*

### 6.5.2 North Cape Shale Max Flooding Surface, Latest Haumurian (66 Ma)

Deposition of the North Cape Shale during the Latest Cretaceous took place in a similar shallow water environment to the E Shale, with a key difference that emergent highs were more prevalent during the Late Cretaceous than the Eocene. Preservation of marine shales extended more proximally inland even though the depressions caused by rifting were not yet infilled. The shoreline shape borders the uplifted horst blocks in places, especially along the flanks of the Maui High. The Aihe High was possibly a peninsula or an island during this period, with the Hector Platform covered by a shallow seaway, and was probably influenced by the wave base - generating a wave cut platform on the crest and deeper water on the downwards flanks. Sediment supply appears to be from the south and southeast and from the eroding edges of exposed fault tips.

Amokura-1 and Matuku-1 again sit in the more distal area within similar depositional environments to the E Shale (marine – inner shelf). A slight thickening of the shale facies at Matuku-1 vs Amokura-1 is attributed to erosion/onlap in the latter location. Distally to the north and west, the strata is expected to increase in thickness and represent an area of probable high quality seal rocks.

A seismic transect directly east of Matuku-1 (Figure 6.4) shows that the eastern boundary of the marine facies ends only a short distance (11 km) from this well's location before pinching out along a north-south line abruptly against the Maui High. The absence of Cretaceous aged sediments in Rahi-1 suggests this was a prominent structure during the Late Cretaceous. As Figure 6.4 demonstrates, the paleoshoreline around the Maui platform is the easiest to define with reflector terminations and the probable appearance of coal measures in the proximal direction further east. As the K95-K91 onlaps the basement high downdip of the coal measures, this suggests they are from a younger overlying unit, probably the Farewell "G" member (Paleocene aged).

The southern shoreline boundary presents a more difficult mapping task. A narrow seaway is inferred to exist between Rahi-1 and Whio-1 based on the eastward continuation of seismic reflectors beyond the study area. Reworking from the later Paleocene regressional event responsible for the Farewell Formation has likely removed some of the shoreline deposits in this area. Despite this, the marine transgression is interpreted to have had an effect a considerable distance further south than the E Shale with most basement highs seeing marine conditions. Active or recently active faulting at this time clearly had greater influence on deposition compared to the E Shale, with the main depocenter being the Kahurangi Trough.

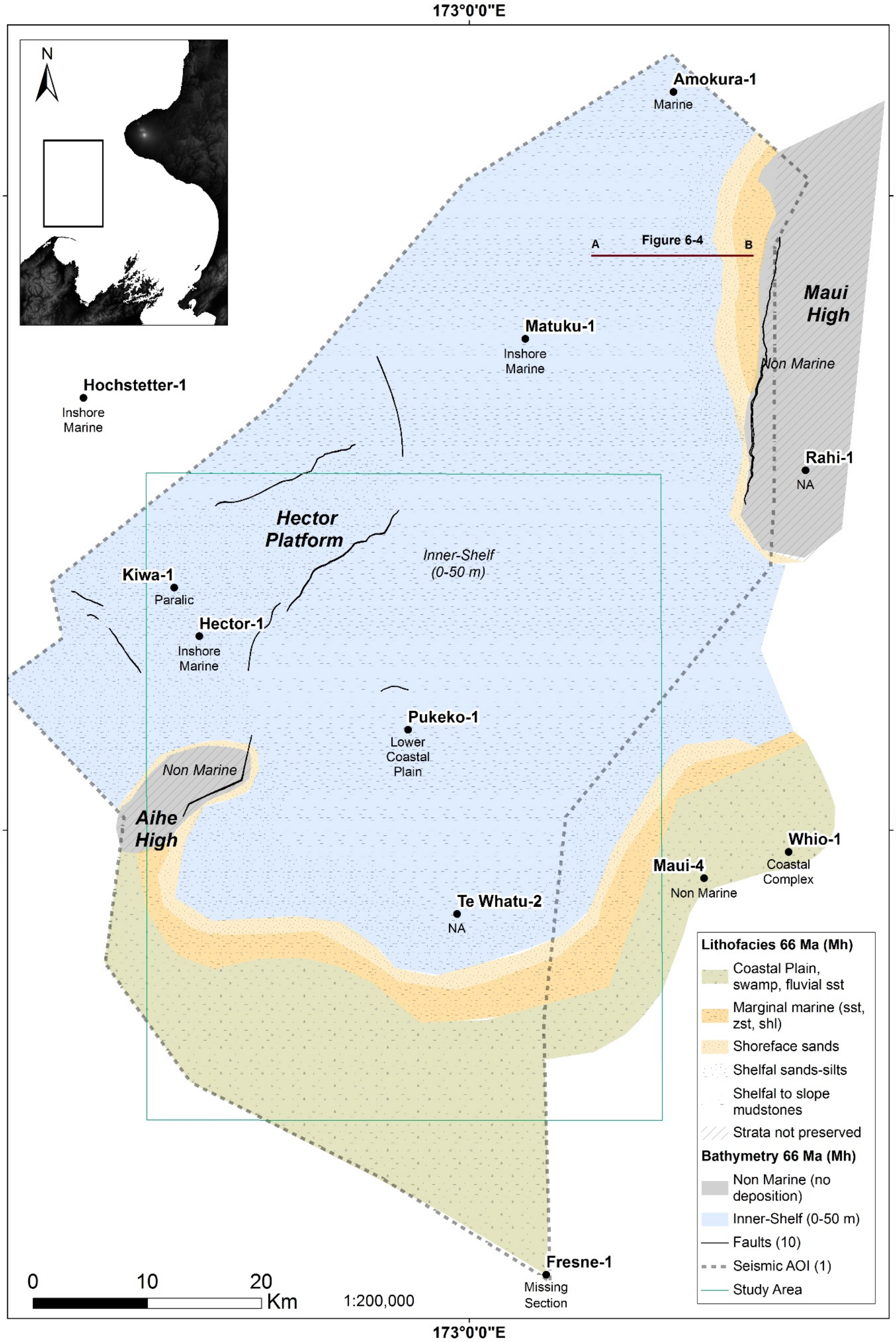



*Figure 6.3 North Cape Shale paleogeographic map at Latest Haumurian (66 Ma)*

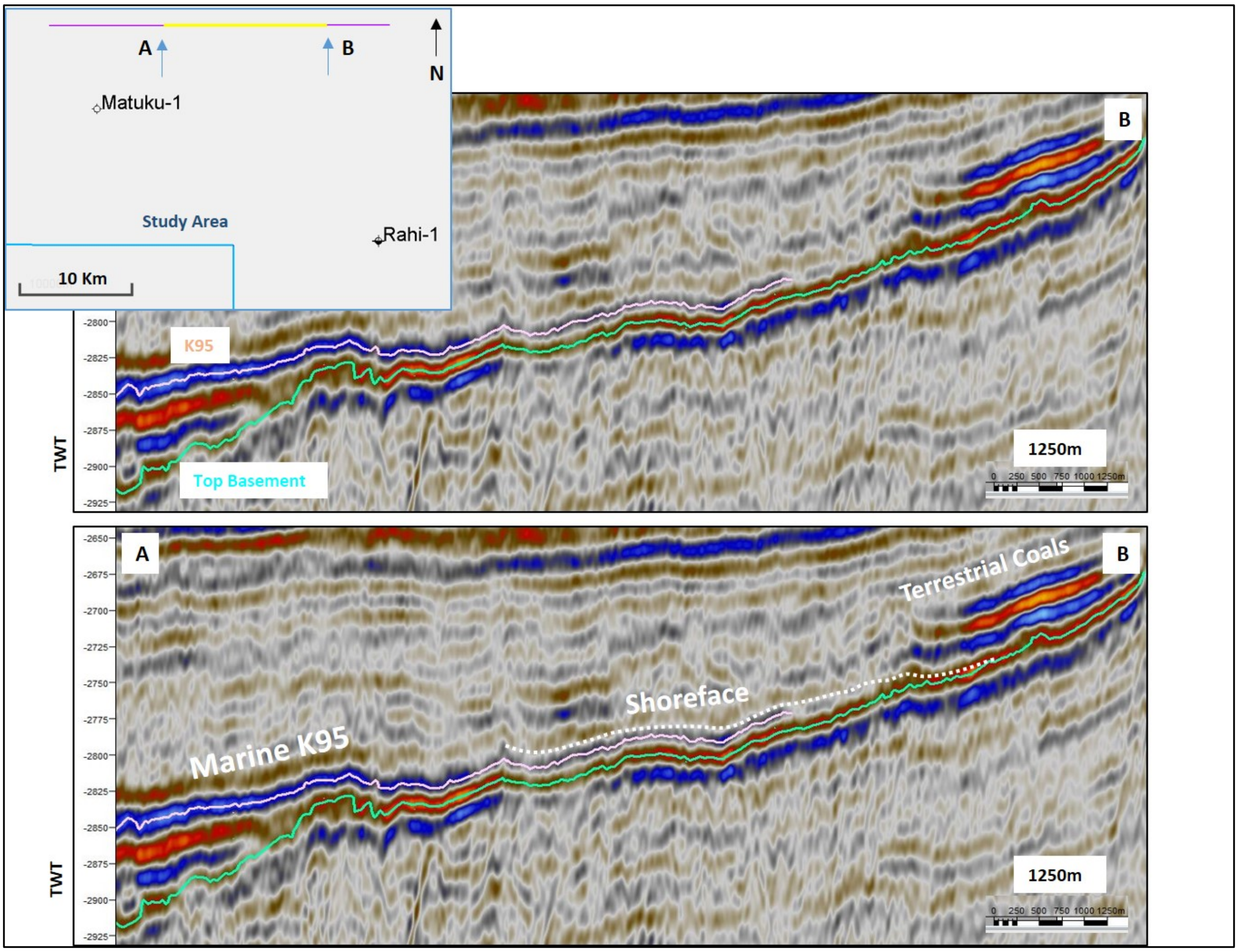



*Figure 6.4 TOKE07-01 2D line showing preserved shoreface K95-91 section above basement*

Confirmed distribution of North Cape Shale ends at Pukeko-1. Evidence for the southern extent of the marine transgression was based solely on seismic character but the discontinuity and depth of the K95 seismic horizon made it difficult to confirm where the shoreface boundary sits. A moderate confidence seismic interpretation shows that North Cape Shale does appear to reach the edge of the Te Whatu inversion structure. Beyond this point within the 3D dataset, North Cape Shale is obscured by faulting and a dimming of seismic amplitudes, which could suggest a facies change. It may also be related to depth, faulting, steep dips not imaging properly or thinning stratigraphy. North Cape Shale could possibly extend further south if accommodation space was available on the downthrown south eastern side of the Te Whatu fault.

## 6.6 Summary and Conclusions

E Shale represents an upside seal for Paleocene reservoirs with a higher probability of marine facies in the north-west of the study area and low probability from Pukeko-1 south. The shoreline boundary exists in a NE-SW pattern a short distance to the north of Pukeko-1 with limited distribution within the Kahurangi Trough to the south of this point, most likely in a marginal marine environment with a lower probability of good quality seal present. It represents a high risk of seal breach for any Paleocene to Cretaceous aged reservoirs within the southern part of the study area and a lower risk within the Kahurangi Trough to the north of Pukeko-1.

North Cape Shale represents the best possibility of a continuous topseal in the area south of Pukeko-1 for Cretaceous reservoirs. Unless capped by this unit, any Cretaceous traps would immediately leak into the overlying strata. The southern boundary cannot be identified with certainty but most likely exists some distance to the north of Fresne-1, at or about the Te Whatu-2 location. As the Te Whatu Inversion was forming in association with normal faulting during the Cretaceous – Paleocene (reactivated in Miocene as reverse) this could have provided a depression for North Cape Shale to be preserved; however there is no direct evidence from seismic or otherwise to support this hypothesis.

# 7. Summary and Conclusions

## 7.1 Project Outcomes

This study investigated the distribution and seal integrity of two marine transgressive claystones - North Cape Shale and the E Shale, deposited in the Latest Haumurian (66 Ma) and Waipawan (55 Ma) in the offshore southern Taranaki Basin, New Zealand. Analysis was based on an examination of offset wells, including wireline logs and core samples, together with interpretation of seismic reflection surveys. The study has delivered the following outcomes:

- Mapping of the southern extents of each marine transgression associated with shale formation;
- Interpretation of where facies boundaries changed from wholly marine to marginal marine/terrestrial;
- Collation of the existing dispersed petrographic and mercury injection pressure data acquired in these two units;
- Presentation of higher resolution paleogeographic maps for the Waipawan and Latest Haumurian transgressional events;
- Identification of areas that are likely to be at higher risk of top seal breach.

## 7.2 Conclusions

Detailed investigations carried out during the course of this study confirms that topseal absence over Paleocene and Cretaceous reservoir targets is a key risk to successful exploration in the southernmost Taranaki Basin. Both marine claystone packages where sampled contain a variety of clay minerals and are variably made up of clay, silt and fine sandstone. No specific clay mineral composition was identified as being indicative of an increased likelihood of having enhanced seal potential, with the best seals located at interpreted maximum flooding surfaces within the middle of the units (Matuku-1, 3816m and 4294.7m).

Seismic interpretation and well results show that the North Cape Shale deposited during the Latest Cretaceous was more widespread than the E Shale, and should be an effective caprock for the North Cape Formation where present, especially in the northern half of the study area. In the area from Te Whatu-2 to the southern border of the study area, its presence is not able to be seismically confirmed and it is considered to be at a higher risk of failure as it changes to a terrestrial facies.

The Waipawan aged E Shale appears to be limited in distribution in the southern Taranaki Basin. Apart from the northernmost part of the study area, E Shale aged sediments consist of coastal plain deposits with limited scope for widespread claystone to be preserved above any Paleocene aged reservoirs. Topseal is therefore considered to be at a high risk of failure for reservoirs in the Farewell Formation within the study area.

## 7.3 Implications for Future Exploration in the Southern Taranaki Basin

This study has identified the following points which should be considered if further exploration is carried out in or in close proximity to the study area:

- Farewell Formation reservoirs have a moderate chance of being sealed by a marine claystone “E Shale” in the north-western segment of the study area (Figure 7.1). The area surrounding, and to the south of, Pukeko-1 has a high risk of inadequate top seal rocks which would allow vertical hydrocarbon leakage.
- Leads and prospects previously identified by exploration companies operating in the area (Aihe, Pukeko East, Paikea and Te Whatu) are considered to be at a high risk of failing for reasons of top seal breach at the Farewell level.
- Three of these identified structures, Paikea, Pukeko East and Te Whatu, should retain prospectivity in the Late Cretaceous North Cape Formation. Aihe appears to be missing significant thicknesses of North Cape Formation and it is doubtful an effective reservoir/seal pair is present.
- Prospectivity may be present at shallower stratigraphic levels (Mangahewa and Kaimiro Formations) for Aihe and Paikea, though analysis of the seal effectiveness at these levels is beyond the scope of this work. At Te Whatu, this shallower prospectivity has already been drilled and only the deeper Farewell and North Cape levels remain untested.
- The North Cape Shale has a higher probability of being present over a wider area, extending further south than the E Shale, but confidence in its presence decreases south of the Pukeko-1 location due to diminishing data quality and probable thinning of the unit.

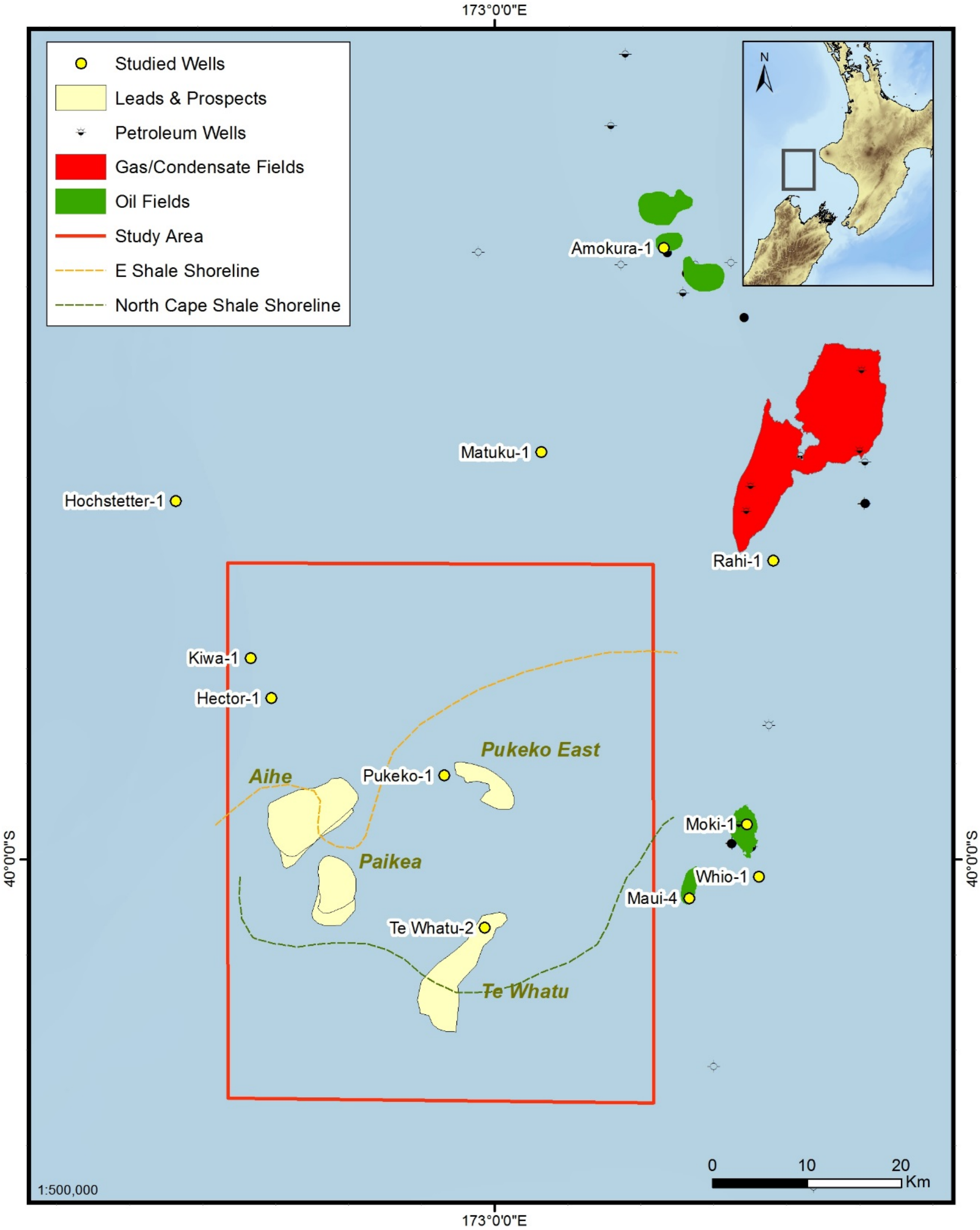



*Figure 7.1 Identified leads at Farewell and North Cape Formation levels in relation to the study area. The potential traps are structural, with four way dip closures or three way closures against faults containing prospective reservoir-seal pairs at multiple levels. Lead outlines from Viscovic and Reynolds (2015).*

## 7.4 Future Work

Greater confidence in the extent of the shoreline position could be resolved by provision of further seismic reflection data, possibly by a more modern reprocessing of the Pipeline 3D or by regional 3D surveys such as those recently acquired by PGS in 2016 and WesternGeco in 2017/18. Both these surveys are multi-client products that were unavailable for use in this work but may have helped to identify a more confident southern shoreline boundary for both seal horizons.

Confirmation of competent seal distribution and confirmation of the facies type as marine claystone or otherwise ultimately requires further wells to penetrate the Waipawan and Latest Haumurian sections. If these are encountered, an analytical programme including sidewall coring in the seal sections should be considered, along with texture descriptions and mercury injection tests. A fully cored section would provide the best dataset possible but would be unlikely to occur unless a commercial sized discovery is made within Farewell or North Cape Formation reservoirs.

Further examination of the texture of the seals over cored sections in conjunction with additional mercury injection capillary testing from existing well samples would provide further support for the findings of this research, and could confirm if rock texture (parallel laminations) plays a significant role in generating high MICP entry pressures in the Taranaki Basin. Detailed analysis of image logs acquired, such as Formation Micro Imaging analysis, may give insight into the amount of laminar bedding and be correlated with existing and further sidewall core analyses.

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**Part II (petroleum reports)**

Below is a list of unpublished petroleum reports used as part of this thesis. These reports are held by the Ministry of Business, Innovation and Employment, and are available free of charge on their website: https://data.eat.nzpam.govt.nz/GOLD/system/mainframe.asp

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# Appendix 1: Petrography

*Separately attached as a Microsoft Excel spreadsheet*

# Appendix 2: Mercury Injection Test Results

*Separately attached as a Microsoft Excel spreadsheet*

# Appendix 3: Well Synopsis

Wells names italicised are located outside the study area. All depths quoted are in metres along hole below the drilling datum.

***Amokura-1* (2004)**

Amokura-1 was drilled by New Zealand Overseas Petroleum Limited as a follow up to the 2003 Tui-1 “F” sands oil discovery in a basement drape structure within the Farewell Formation. The well was drilled vertically in 121.9 metres of water by the semi-submersible rig Ocean Bounty to a total depth of 3995.5 metres, finishing in granitic basement. A 12.2 metre oil column was encountered between 3674 – 3686.2 metres, sealed by a 177-metre claystone dominated E Shale package. 18 metres of core was obtained at the base of the sealing facies and over the topmost section of oil bearing reservoir. Amokura-1 was plugged as suspended as an oil discovery ([1]NZOP, 2004).

***Cape Farewell-1* (1986/87)**

Cape Farewell-1 is an onshore deviated well targeting an offshore structural closure at the southern extreme of the Taranaki Basin. Drilled by Whitestone New Zealand Ltd and Petrocorp using OD&E rig 17, the well spudded into Farewell Formation at surface, reaching a total depth of 2817 metres before being abandoned short of the pre-drill target due to drilling difficulties within Cretaceous aged sediments (Rakopi Formation equivalent). No commercially significant oil or gas shows were recorded with the drilled section consisting predominantly of terrestrial coal measures, sands and conglomerate. No E Shale or North Cape Shale was encountered (Whitestone NZ Ltd, 1987).

***Fresne-1* (1976)**

Fresne-1 was drilled by New Zealand Aquitaine Petroleum Ltd targeting a four way dip closure. The drillship Glomar Tasman spudded the well in 74 metres of water, and drilled vertically to a total depth of 2503 metres, finishing in Cretaceous aged sediments (NZ Aquitaine Pet. Ltd, 1976). Fresne-1 recorded oil shows in the mud logs but no commercially significant hydrocarbon accumulations were intersected. Like Cape Farewell-1 it also failed to encounter the E Shale or North Cape Shale at its location.

**Hector-1 (2007)**

Hector-1 was a vertical well designed to test a combination stratigraphic/structural trap formed by a westward shaling out of the Mangahewa sands within a four-way dip closure that was left untested by Kiwa-1. Further updip potential was identified in the Farewell and North Cape Formations. Pre-drill, 3D seismic gave good support to this play concept. The structure was thought to be in a position more proximal than Kiwa-1 (1981) that failed to encounter any well-developed sand at the Mangahewa interval. Spudded by the Ocean Patriot semi-submersible in 171.5 metres of water, a total depth of 3825.2 metres was reached with the well finishing in granitic basement. Hector-1 was successful in that it did encounter Mangahewa sands but no commercially significant hydrocarbons were present at any interval. Both the E and North Cape Shale were encountered. Hector-1 was subsequently plugged and abandoned as a dry hole (AWE, 2007).

***Hochstetter-1* (2000)**

Hochstetter-1 was a bold attempt to test prospectivity in the western Taranaki Basin. Drilled using the Ocean Epoch in 195 metres of water, the target was a four-way dip closed structure at the Kaimiro and Farewell Formation levels, with an upside stratigraphic component in the Kaimiro as these sands were interpreted to be pinching out to the west. Charge to the structure was proposed to have occurred from the Kahurangi Trough up the bounding West Cape fault. Hochstetter-1 reached a total depth of 3298 metres within the Farewell Formation after encountering the E Shale. Only minor oil shows were observed in the Kaimiro Formation with no commercial significance, and the well was plugged and abandoned as dry (New Zealand Oil & Gas, 2000).

**Kiwa-1 (1981)**

Drilled by Shell BP & Todd Oil Services in 1981 using the Sedco 445 drillship, Kiwa-1 targeted a large low relief four-way dip closed structure. The target Kapuni Group (Kaimiro and Farewell Formation) sands were encountered but the Mangahewa Formation was missing at this location. No significant hydrocarbon shows were encountered, and after tagging granitic basement the well was plugged and abandoned as a dry hole. Both the E Shale and North Cape Shale were encountered (Shell BP & Todd, 1982).

***Matuku*-1 (2013-14)**

Matuku-1 was a vertical well operated by OMV New Zealand in 2013/2014. The well was drilled by the Kan Tan IV semi-submersible rig in 120 metres water, targeting a four way dip closure between Eocene to Late Cretaceous levels. Matuku-1 reached a total depth of 4846 metres in Rakopi Formation just above the interpreted basement. The target Paleocene and Late Cretaceous sandstones were both water wet, and Matuku-1 encountered no substantial hydrocarbon shows. Thick packages of E and North Cape Shale were encountered. The well was plugged and abandoned as a dry hole (OMV, 2014).

***Maui-4* (1970)**

Drilled at the end of the initial campaign by Shell, BP and Todd Oil Services that discovered the Maui field, Maui-4 targeted a separate smaller inversion structure on the same trend, some 30 kilometres south of the Maui field. Drilled to granitic basement at a total depth of 3919 metres, it made what was at that time an uncommercial oil discovery in the upper Kapuni Group (Mangahewa Formation), the Manaia field. After flow testing oil, the well was plugged and abandoned as an uncommercial oil discovery (Shell, BP & Todd, 1970). No E shale was noted, but a 100m section of siltstone was noted at the top of the North Cape Formation which is interpreted to represent a proximal age equivalent of the North Cape Shale.

**Pukeko-1 (2004)**

Pukeko-1 was a vertical well drilled by New Zealand Overseas Petroleum to test a stacked series of four-way dip closures over a basement high. Reservoirs at the Eocene, Paleocene and Cretaceous levels were targets. Drilled using the Ocean Bounty semi-submersible rig in 132.2m of water, the well reached a total depth of 4190 metres, finishing in granitic rocks. Good oil shows in the base Farewell and North Cape Formations were encountered, however wireline logging and formation tests showed the reservoirs to be of poor quality incapable of flowing hydrocarbons. The well was plugged and abandoned as a non-commercial technical oil discovery (NZOP, 2004). North Cape Shale was encountered, with no marine E Shale facies observed. Importantly, despite being an economic failure, Pukeko-1 demonstrated a working petroleum system in the Kahurangi Trough section of the Taranaki Basin by the live oil shows.

***Rahi-*1 (1996)**

Rahi-1 was drilled by Shell Todd Oil Services to test an apparent dip closed fault bound structure at the southern extreme of the Maui B field. The semi-submersible rig Sedco 703 spudded and well in 106 metres of water and drilled vertically to a total depth of 3501m, finishing in an unusual basement lithology of metamorphic schist and conglomerates. While the pre drill stratigraphy was correct, the target formation tops were all encountered low to prognosis suggesting that an error with in the seismic data had resulted in the targeted structure likely to have been an artefact of an incorrect depth conversion. Good oil shows were observed in the Mangahewa Formation with minor shows in the Kaimiro and Farewell but no commercial saturations were calculated after assessment of wireline logs (STOS, 1996). A thin section of E Shale was noted in Rahi-1, and no North Cape Shale is preserved at this location due to the formation onlapping the Maui basement high down dip of this location.

**Te Whatu-2 (1987)**

Te Whatu-2 was a re-drill and deepening of the Te Whatu-1 well after technical problems forced its premature abandonment at 930m. The target was a four way dip closure at the Mangahewa to Kaimiro sand levels within a compressional anticline. Drilled by Petrocorp Exploration Limited using the Zapata Arctic semi-submersible rig in 114m of water, a total depth of 3542 metres was reached, with the well terminating in the Kapuni Group (Kaimiro Formation) before reaching the E or North Cape Shales. No significant shows were observed and the well was plugged and abandoned as a dry hole after running wireline logs (Petrocorp, 1988).

***Whio-1* (2014)**

Whio-1 is a deviated well drilled by OMV New Zealand in 2014. The well was drilled by the Kan Tan IV semi-submersible rig in 98 metres water. Whio-1 reached a total depth of 2824 metres in Paleocene aged sediments (Farewell Formation). The target Miocene and Eocene sandstones in two slightly offset four-way dip closures were both intersected in a near crestal position but despite its location only five kilometres from Maari field, Whio-1 encountered no substantial hydrocarbon shows at either level. Thin Waipawan aged proximal shales were encountered. The well was abandoned as a dry hole (OMV, 2015).

# Appendix 4: Composite Logs

*Separately attached as individual prints for each well*

# Appendix 5: Volume of Clay ($V_{cl}$) Calculation Sheets

*Separately attached as Microsoft Excel spreadsheets (2)*

# Appendix 6: Neutron/Density Plots

*Separately attached as Microsoft Excel spreadsheets (2)*

# Appendix 7: Seismic Survey List

*Separately attached as a Microsoft Excel spreadsheet*

# Enclosure 1: E Shale TWT Surface Map

Enclosure 2: North Cape Shale TWT Surface Map